United States
Environmental Protection Agency

Air and Radiation
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EPA Coalbed Methane Outreach Program Technical Options Series

USE OF COAL MINE METHANE IN BLAST FURNACES

Gas injection systems increase the iron-making productivity of blast furnaces while lowering costs
(Photo Courtesy of American Iron and Steel Institute)

POTENTIAL BENEFITS OF INJECTING COAL MINE METHANE IN BLAST FURNACES...

- Reduces coke usage and improved furnace stability
- Increases iron-making productivity and reduced operating costs
- Reduces air pollution from coke
- Recovery and use of coal mine methane reduces greenhouse gas emissions

Why Consider Using Coal Mine Methane in Blast Furnaces?

Using coal mine methane as fuel, rather than venting it to the atmosphere, reduces methane emissions

The steel industry uses blast furnaces to transform iron ores into molten iron, which is later used for steelmaking. Blast furnace operations use metallurgical coke to produce most of the energy required to melt the ore to iron. Currently, U.S. steelmakers produce approximately 55 million tons of molten iron annually, requiring about 23 million tons of coke per year. However, coke is becoming increasingly expensive since coke production is declining for various reasons. Since blast furnaces will continue to be the major process for producing iron in the United States, the steel industry is seeking low-capital options that reduce coke consumption, increase productivity, and reduce operating expenses.

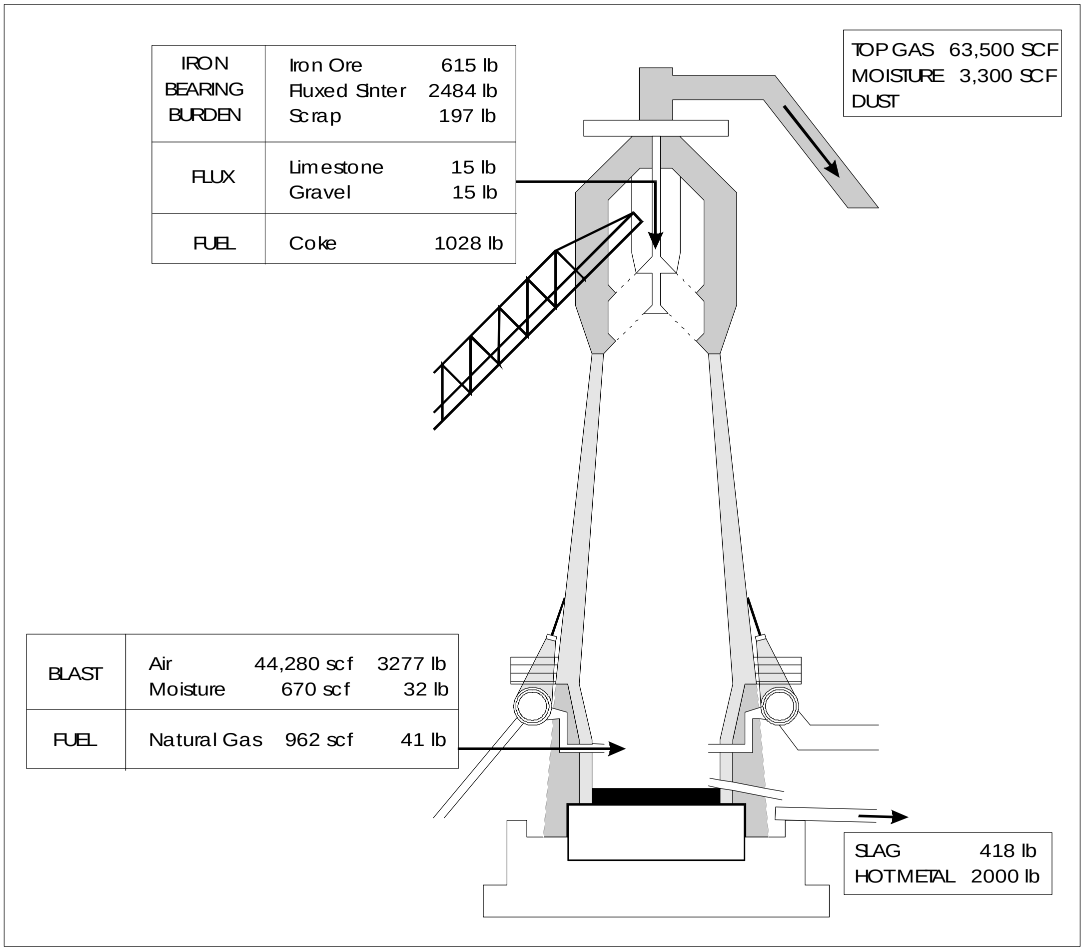
All blast furnaces in North America inject some type of supplemental fuel, such as natural gas, coke oven gas, oils and tars, or coal to form additional carbon monoxide and hydrogen for combustion, and chemical reduction of iron-bearing materials into molten iron. Of these fuels, natural gas and pulverized coal are the most widely accepted for injection. Recent full-scale tests have shown that injecting natural gas into blast furnaces at the rate of 6,900 standard cubic feet per ton of hot metal (scf/thm) can reduce coke consumption by 30%, and can increase ironmaking production by 40%. Injecting natural gas, rather than coal or coke oven gas, as a supplemental fuel also reduces NOx and SOx emissions. Coal mine methane provides the same benefits as conventional natural gas, and could easily be substituted for, or mixed with, natural gas for blast furnace use, as long as it meets gas quality requirements (it must have a low sulfur content and contain at least 94% methane).

Blast furnaces near gassy coal mines may be able to use coal mine methane to offset a portion of their natural gas needs

In the U.S., several blast furnaces that currently inject natural gas are located within approximately 20 miles of gassy coal mines. Because most gassy coal mines drain less than 10 million cubic feet of methane per day, they do not produce enough methane to meet all the gas requirements of a typical blast furnace, but one or more gassy mines could produce enough methane to supplement a blast furnace's gas needs. A preliminary review suggests that a dedicated pipeline project delivering coal mine methane to a blast furnace is not likely to be economically viable. However, this review did not take into account many variables, including a steel company's interest in greenhouse gas reduction credits, locations of existing pipelines with respect to the blast furnaces, and the potential for innovative strategies for transporting methane from a mine to a blast furnace. These site-specific conditions could improve the economics of using coal mine methane in blast furnaces. Internationally, there may be additional opportunities for the use of coal mine methane in blast furnaces, as in many countries, large metallurgical industries are located near coal mines.

The cost of coal mine methane is often less than conventional natural gas

Several companies are currently reporting their methane emissions reductions under the DOE-sponsored "Voluntary Reporting Program" for greenhouse gas emissions. At present, these emissions reductions do not have an established market value. However, at least two companies, Niagara Mohawk Power Corp. and Suncor Energy Inc., have taken a first step toward the creation of a global market and an international trading system for reductions in emissions of greenhouse gases, such as methane and carbon dioxide. Specifically, Suncor Energy has agreed to purchase greenhouse gas emission reductions from Niagara Mohawk. Steel companies wishing to participate in a greenhouse gas emissions reduction program may wish to use coal mine methane to offset a portion of their fuel needs.



Schematic of a typical blast furnace injecting natural gas (962 scf per ton of hot metal)

The process places iron ore, coke and other fluxing substances into the furnace top *(upper left diagram)* while blowing a blast of hot air enriched with natural gas into the furnace bottom *(lower left)*. The coke generates gases that reduce the ore, creating molten iron and slag *(lower right)*. The process also produces blast furnace gas, or "top gas" *(upper right)* that is suitable for use in the furnace stoves or elsewhere in the plant.

	No Gas Injection	1780 scf gas per ton of hot metal	3340 scf gas per ton of hot metal	5800 scf gas per ton of hot metal
Metal production (tons/day)	2,589	2,918	3,124	3,452
Coke cost ($/THM)	$59.00	$52.00	$48.00	$41.00
Natural gas cost ($/THM)	$0	$3.80	$7.50	$12.60
Oxygen Cost ($/THM))	$0	$0.10	$2.60	$4.90
Iron Ore Pellets ($/THM)	$57.80	$57.60	$57.70	$57.70
Total Cost ($/THM)	$117.00	$113.50	115.80	$116.20
Cost Savings ($/Day)	--	$10,740	$4,280	$2,420

Increased Production ($/Day)	--	$32,900	$53,500	$86,300
Total Benefits ($/Day)	--	$43,460	$57,780	$88,720
Material Costs: Coke - $115/ton; Natural gas - $2.20/mcf; Oxygen - $35/ton; Ore pellets - $38/ton				
Abbreviations: scf – standard cubic feet; THM - tons of hot metal; mcf - thousand cubic feet				
All data derived from Gas Research Institute Report, "Natural Gas Injection in Blast Furnaces"				

For More Information...

Rapidly changing environmental regulations and market conditions are creating new opportunities for distribution and use of coal mine methane. Blast furnaces are a high-volume gas consumer that could benefit from using coal mine methane to meet a portion of their fuel needs. The use of coal mine methane, like conventional natural gas, reduces coke consumption, and therefore NOx, SOx, and CO_2 emissions. In addition to these benefits, the use of coal mine methane reduces methane emissions.

To obtain more information about using natural gas in blast furnaces, contact:

Dave Smith
Program Team Leader
Industrial Business Unit
Gas Research Institute
8600 West Bryn Mawr Avenue
Chicago, IL 60631-3562
Telephone: (773) 399-5471
Fax: (773) 399-8170

To obtain information about blast furnace operations, contact:

William A. Obenchain
Manager, Manufacturing and Technology
American Iron and Steel Institute
1101-17th Street, NW
Washington, DC 20036-4700
Telephone: (202) 452-7208
Fax: (202) 463-6573

Or contact EPA's Coalbed Methane Outreach Program for information about this and other profitable uses for coal mine methane:

Coalbed Methane Outreach Program
U.S. EPA (6202J)
401 M Street , SW
Washington, DC 20460 USA
(202) 564-9468 or 564-9481
Fax: (202) 565-2077
e-mail: fernandez.roger@epa.gov
schultz.karl@epa.gov

http://www.epa.gov/coalbed

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COAL MINE METHANE USE IN BRINE WATER TREATMENT

Coal Mine Methane-Fueled Evaporator at Morcinek Mine, Poland
(Photo Courtesy of Aquatech Services, Incorporated)

AN INTEGRATED APPROACH TO DISPOSAL OF PRODUCED BRINES

- Wastewater treatment process uses coal mine methane as fuel
- Can be an economically viable alternative to other water management methods
- Appropriate for coal mines and coalbed methane fields producing large volumes of saline water
- Produces fresh water suitable for domestic, industry, or agriculture usage
- Can use medium quality gas (as low as 50 percent methane)

The use of coal mine methane enhances brine water treatment economics while reducing emissions of methane to the atmosphere

Why Consider Coal Mine Methane Use in Brine Treatment?

Coal mines and coalbed methane wells often generate large volumes of water, which may be highly contaminated with salt and other minerals. Because these brines can alter water quality, they must be disposed of in compliance with national and local statutes. Energy producers are continually seeking to improve economics by decreasing water management costs.

Many coal mines drain methane from gob areas (collapsed rock over mined-out areas). Mine ventilation air contaminates gob gas, often rendering it unsuitable for pipeline injection. Therefore, mines usually vent this gas to the atmosphere instead of using it. By using this gas as a fuel in the brine water treatment process, coal mines can reduce the cost of desalination while helping to mitigate greenhouse gas emissions.

Over the last three years, the use of coal mine methane in brine water desalination has been successfully demonstrated at the Morcinek coal mine in Poland's Upper Silesian Coal Basin. The process, designed by Aquatech Services, Incorporated, integrates pre-treatment regimes, high-pressure reverse osmosis, and a final concentration of the salt in a submerged combustion evaporator. The pretreatment regime is specially designed for the complex waste streams typical of coalbed brines. Following pretreatment, a reverse osmosis system converts the brine wastewater to usable fresh water and a brine-salt slurry. Evaporation units, fired by medium-quality gas recovered from the Morcinek Mine, further concentrate the residual slurry to dry salts for commercial use or underground disposal.

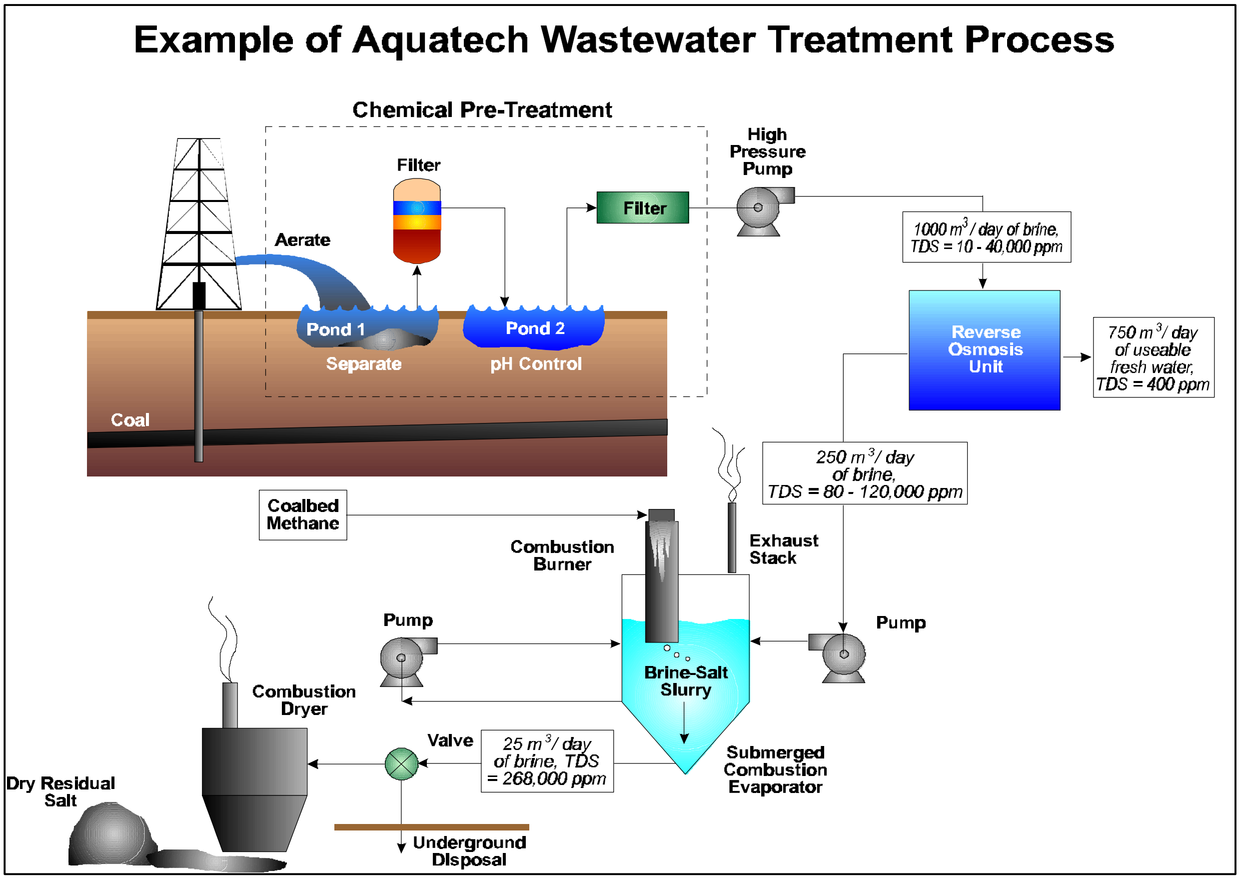
Desalination plants typically have large fuel requirements, and coal mine methane is a clean, low-cost fuel

The demonstration project at the Morcinek Mine is treating more than 50 cubic meters (314 barrels) of waste water per day. Testing of the demonstration equipment began in 1994, with support from the U.S. Department of Energy, U.S. Environmental Protection Agency, and Polish government. All results have been positive, demonstrating efficiencies greater than anticipated, and validating and confirming process reliability.

Some Facts About Using Coal Mine Methane for Waste Water Treatment (based on results of the demonstration project at the Morcinek Mine)

- Treatment costs are competitive with those of underground injection
- Modular design allows for wide range of effluent volumes
- Process can recover more than 60% of the feed stream as usable fresh water, suitable for domestic uses in many cases
- Process offers total brine volume reductions of greater than 95%
- Suitable for coalbed methane wells in unmined areas, as well as coal mining operations
- Can use medium quality gas (as low as 50% methane)

Desalination processes (unlike underground injection) can produce fresh water for crop irrigation, domestic, and industry use



Comparison of Aquatech Process (Using Coal Mine Methane as Combustion Fuel) to Underground Injection

Parameter	Reverse Osmosis Followed by Combustion Evaporation (Aquatech)	Underground Injection Only [1]
Typical capital costs ($US)	$3,000 per m^3/day $480 per bbl/day	$1,260 - $5,660 per m^3/day $200 - $900 per bbl/day
Typical operating costs ($US)	$2.00 - $3.00/$m^3$ [2] $0.32-$0.47/barrel	$0.60- $4.70/$m^3$ $0.10-$0.75/barrel
Conversion to usable water	YES	No
Production of usable salts	YES (in some cases)	No
Uses coal mine methane[3]	YES	No
Total brine volume reduction	>95%	0%
Life of plant or well (years)	10	20

(1)Underground injection costs and well life vary widely according to site-specific conditions. Costs shown are from 1995 assessment of water disposal practices in the U.S., published by the Gas Research Institute (GRI), and from an unpublished report on disposal of produced waters in the San Juan Basin prepared in 1992 for GRI. Costs shown do not include off-site transportation. Twenty years is the average injection well life according to Warner and Lehr, 1977, An Introduction to the Technology of Subsurface Wastewater Injection: A symposium in Worthington, Ohio.

(2)On a lease-purchase basis

(3)Coalbed methane can be an economical fuel source for treatment of water produced from coal mining operations or coalbed methane wells. Use of methane produced during coal mining operations is especially attractive in that in most cases, this methane would otherwise be vented to the atmosphere. This “waste gas” is a valuable fuel source if mines use it, otherwise, it is a potent greenhouse gas that causes global warming.

For More Information...

Energy producers are continually seeking to improve economics by decreasing water management costs. Coal mine methane used as fuel for a wastewater treatment process is an economic means of wastewater management that can also reduce emissions of methane to the atmosphere.

EPA is aware of only one company (Aquatech Services, Incorporated) whose brine water treatment process has employed coal mine methane as a fuel.* To obtain more information about this process, contact:

John H. Tait, Principal
Aquatech Services, Incorporated
P.O. Box 946
Fair Oaks, CA 95628 USA
(916) 966-5141 (Phone and Fax)
e-mail 103220.1655@compuserve.com

Coalbed Methane Outreach Program

Or contact EPA's Coalbed Methane Outreach Program for information about this and other profitable uses for coal mine methane:

U.S. EPA
401 M Street, SW (6202J)
Washington, DC 20460 USA
Tel: (202) 564-9468 or (202) 564-9481
Fax: (202) 565-2077
e-mail: fernandez.roger@epa.gov
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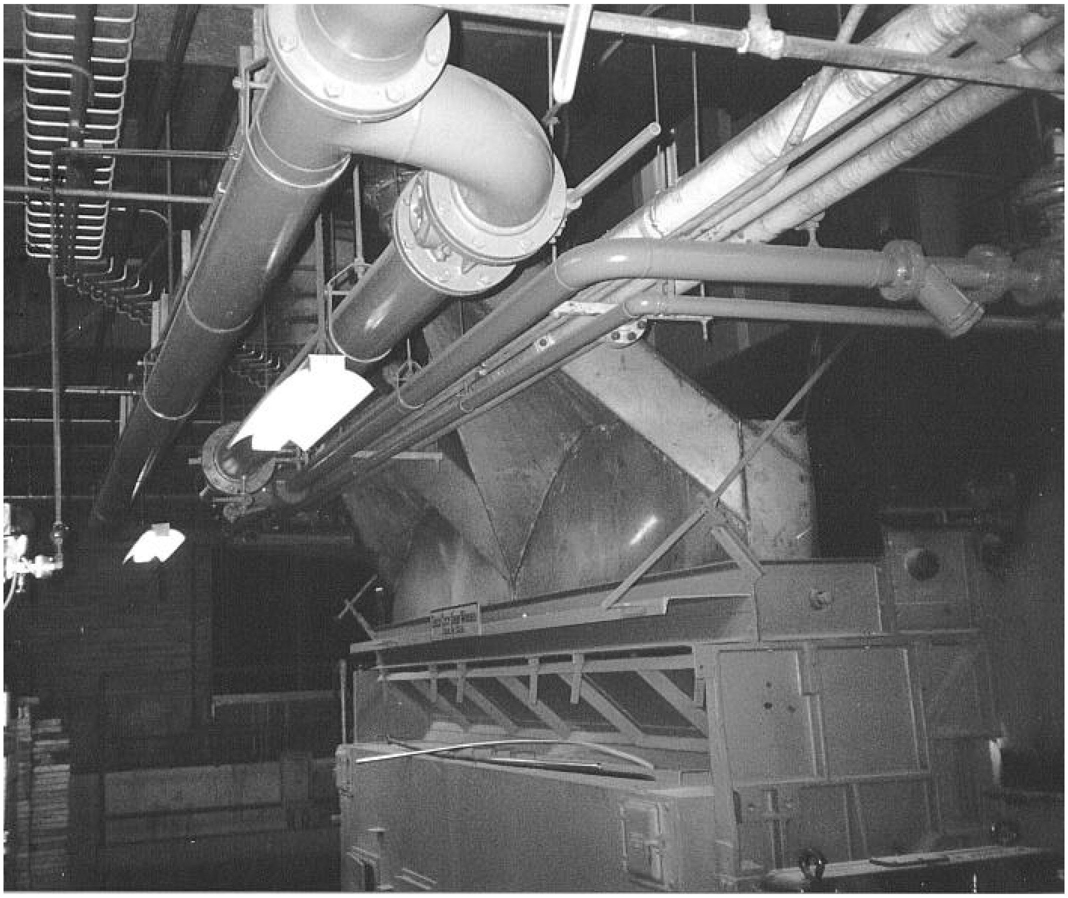
COFIRING COAL MINE METHANE IN COAL-FIRED UTILITY AND INDUSTRIAL BOILERS



Coal Stoker Boiler Equipped for Natural Gas Cofiring
(Photo Courtesy of Energy Systems Associates)

A PRACTICAL, ECONOMICAL USE FOR COAL MINE

- Reduces emissions of SO_2, NOx, CO_2 and methane (a potent greenhouse gas)
- Reduces operating and maintenance costs, and improves stack opacity and ash quality
- Ideal for medium-quality (below pipeline spec) gas that mines recover from gob areas
- Commercially proven using conventional natural gas in the United States and elsewhere
- Commercially proven with coal mine methane

Cofiring is the combustion of gas with coal in the primary combustion zone of a coal-fired boiler

Why Consider Cofiring Coal Mine Methane in Boilers?

Coal mine methane, like conventional natural gas, is an ideal boiler fuel because it requires no storage or preparation for combustion. For years, gassy coal mines in China, the Czech Republic, Poland, Russia, and Ukraine have taken advantage of their abundant supply of methane by cofiring it with coal in their boilers to produce heat and/or electricity. In addition to on-site use at the mine, mines can pipe methane to nearby power plants or other industries for cofiring in their boilers.

The gas input to a boiler may vary from less than 10 percent to 100 percent of total fuel input depending on boiler design, gas availability, and the needs of the boiler operator. The required equipment is commercially available, meets all applicable codes, and, in many cases, is already in place.

Because it contains no ash, virtually no sulfur, and is low in nitrogen, the firing of coal mine methane in coal boilers reduces SO_2, NO_X, and particulate emissions. These benefits are more important than ever before, because of new EPA particulate emissions regulations. The improved combustion achieved with cofiring can also improve carbon burnout and reduce opacity problems. Boiler operators can inject coal mine methane into different areas of the boiler to address a variety of boiler operational concerns, such as slag buildup. The ease of boiler conversion and low capital cost of cofiring can represent a low-risk approach to improving boiler performance. Coal-fired utility boilers in the U.S. consumed more than 70 billion cubic feet of conventional natural gas in 1995. These boilers used this gas for ignition, warm-up, and load carrying.

The benefits of coal mine methane use in coal boilers include improved combustion and boiler control, and reduced pollution

Many gassy coal mines are in close proximity to industrial boilers, and at least ten gassy coal mines in the U.S. are within 20 miles of utility boilers. EPA's Coal Mine Methane Outreach Program has prepared a report (available on request) identifying several potential sites in the U.S. that could economically cofire coal mine methane.

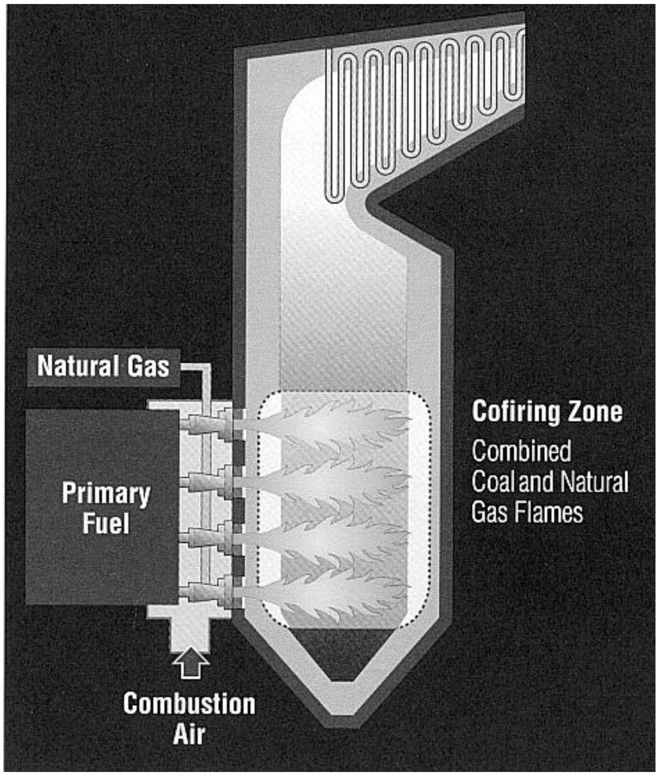
Cofiring Gas in Coal Boilers Can Result in...

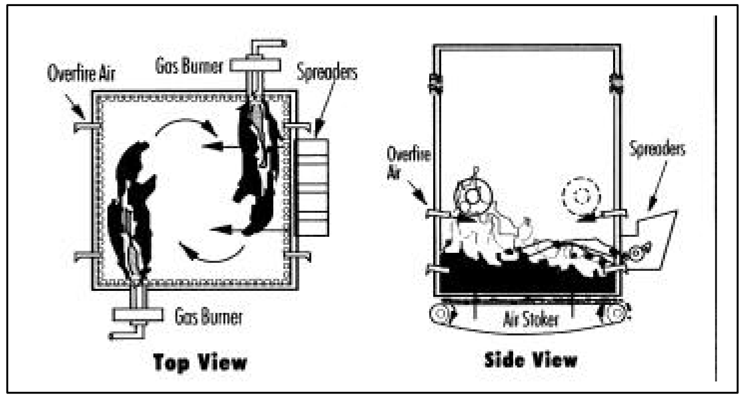
- **Net Cost Savings -** Low capital investment and rapid return on investment
- **Better Efficiency -** Improved carbon burnout, lower excess air level
- **Reduced Emissions** of NO_x, SO_x. particulates, CO_2 and CH_4 (greenhouse gases)
- **Improved Operation -** Easier startup, increased short-term peaking capacity
- **Lower Startup Costs** compared to oil
- **Improved Ash Quality,** making the ash a saleable commodity in many cases

Economics of Cofiring Coal Mine Methane at a Coal Fired Power Plant

EPA analyzed the economics of cofiring coal mine methane in several coal-fired power plants. A project in which 4 mmcf of methane per day replaces 3% of the coal used in a 600 MW boiler located 17 miles from a mine would yield a net present value (NPV) of more than $5 million and an internal rate of return (IRR) of 29%. These results are based on conservative cost estimates for gathering, transportation, compression and boiler conversion. The model also recognizes the economic benefits of NO_X and SO_X reduction achieved by cofiring methane. If the same mine produces 6 mmcf of methane per day for use in the boiler, the NPV is more than $10 million and the IRR is 44%. Economic benefits increase as the volume of methane recoverable increases.

Numerous gassy coal mines in several countries successfully cofire methane in their boilers to produce heat and/or electricity





Various types of boilers can cofire coal mine methane, just as they would conventional natural gas. *Left*, cofiring in a wall-fired utility boiler. *Above*, cofiring in an industrial stoker boiler.

(Illustrations from the Gas Research Institute brochures "Cofiring Case Studies: Competing in a

The Gas Research Institute (GRI) has evaluated the use of cofiring at numerous utility and industrial boilers. More than 370 utility boilers in the U.S. now have cofiring capability, and GRI and others have documented the many benefits. The table below shows how the emission, operation, and performance benefits of cofiring in three diverse cases - a municipal power plant, an institution, and a manufacturing company- more than justify the cost.

Three Industrial Boiler Case Studies: Quantifiable Benefits

Industry/Institution	Dover Light and Power	Oberlin College	The Hoover Company
Boiler Type (all stoker)	17 MW$_e$, 165,000 lb/hr spreader	40,000 lb/hr chain grate	75,000 lb/hr chain grate
% of Gas Cofired	8-15%	20%	40%
Benefits (Emissions Reduction, Improved Operation, Efficiency)	\$0.29 / MmBtu	\$1.67 / MmBtu	\$1.20 / MmBtu
Costs (Fuel Price Increase, Annualized Capital Cost)	\$0.15 / MmBtu	\$0.52 / MmBtu	\$0.78 / MmBtu
Net Cost Savings	\$0.14 / MmBtu	\$1.15 / MmBtu	\$0.42 / MmBtu
Payback (simple)	1.4 years	1.8 years	3.1 years
Benefits Realized	• Efficiency up 3-4% • Particulates down 33% • Recovered lost capacity • Clean, fast light-off	• Eliminated use of separate boiler for low steam demand periods • Improved efficiency	• Emissions reductions • Load following capability • Improved opacity • Gas-only startup
Cost data are approximations based on interpretation of graphs from GRI brochure "industrial Boiler Gas Cofiring".			

For More Information...

Utility plant operators, manufacturers, and institutions are seeking ways to cut costs, improve performance, and comply with air quality regulations. Utilities and other industries recognize the benefits of cofiring gas in coal-fired boilers, and the use of coal mine methane for this purpose may be a profitable alternative to conventional natural gas.

To obtain more information about natural gas cofiring in utility boilers, contact:

John M. Pratapas
Principal Technology Development Manager
Gas Research Institute
8600 W. Bryn Mawr Ave.
Chicago, IL 60631-3562
(773) 399-8301
Fax: (773) 399-8170
email: jpratapa@gri.org

To obtain more information about natural gas cofiring in industrial boilers, contact:

Isaac Chan
GRI Project Manager
Industrial Business Unit
Gas Research Institute
8600 W. Bryn Mawr Ave.
Chicago, IL 60631-3562
(773) 399-5411
Fax: (773) 399-8170
Email: ichan@gri.org

Or contact EPA's Coalbed Methane Outreach Program for information about this and other profitable uses for coal mine methane:

http://www.gri.org

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USING COAL MINE METHANE IN COGENERATION POWER SYSTEMS

3.5 MW gas-fueled standardized cogeneration system at Trigen Energy Corporation facility in Ontario
(Photo courtesy of Trigen Energy Corporation)

ADVANTAGES OF COGENERATION SYSTEMS ARE...

- Can operate at over 80% efficiency using medium quality gas
- Can produce enough on-site electricity to meet the needs of a typical coal mine
- Recovered heat can provide heating and/or cooling for mine facilities
- Can produce thermal energy for nearby industries with boilers or steam turbines
- Use of coal mine methane reduces greenhouse gas emissions

Most coal mines produce enough methane to fuel small-scale cogeneration systems (1-5 MW)

Why Consider A Cogeneration Power System For A Coal Mine?

Many coal mines worldwide drain methane from gob areas (collapsed rock over mined out areas) for safety reasons. Gob wells produce medium quality gas that generally contains 30-80% methane. The gas quality is not suitable for pipeline injection, but mines can use gob gas exceeding 35% methane concentration as fuel for on-site electricity generation. Given their large energy requirements, coal mines can generate electricity on-site and realize significant economic savings, while reducing greenhouse gas emissions.

Coal mine methane has been successfully used to fuel several types of power generating systems, such as internal combustion engines, advanced gas turbines, and cogeneration. Cogeneration systems (also called combined heat and power, or CHP plants), can employ various types of combustion turbines and use waste heat from electricity generation to produce hot air to heat buildings and steam for condensing steam turbines or absorption chiller units. Coal prep plants can use recovered steam for electricity, indirect drying of coal or hot air for direct drying.

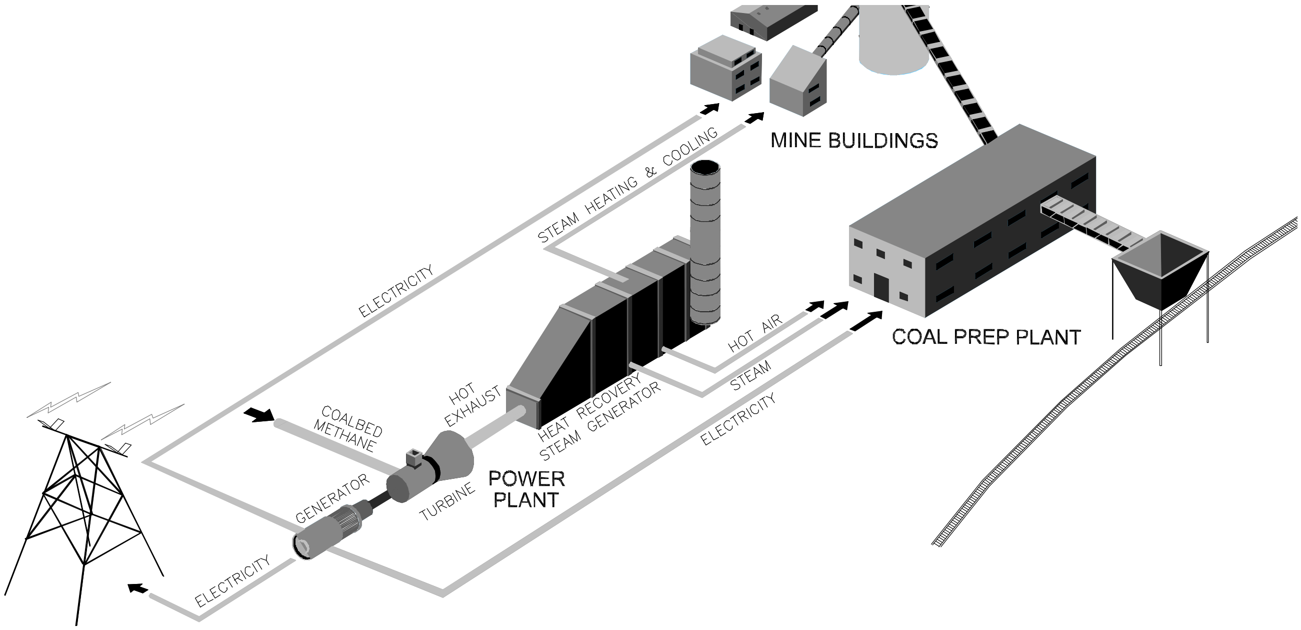
Steam cooling eliminates the use of CFCs and HCFCs

In Europe, cogeneration systems have traditionally been used to produce heat and power for "district heating and cooling" systems serving large-scale residential or commercial complexes. For example, the Zofiowka mine in Poland uses coal mine methane to fuel a cogeneration plant, with the plant supplying heat and power to the mine and the nearby town of Jastrzebie. In addition, several cogeneration systems in Australia use landfill methane as a fuel. Recently, large industries, universities, and hospitals in the U.S. have demonstrated the wide spectrum of applications for cogeneration systems. Plant location is a major factor in determining the economic viability of cogeneration plants at coal mines. Coal mines located in areas with nearby energy-intensive industries such as refineries and chemical, pulp and paper, or metals facilities may be able to export thermal energy to these plants.

The use of coal mine gas helps mitigate emissions of methane, a greenhouse gas. Cogeneration also converts CO_2 into useful energy, further reducing greenhouse gas emissions. Moreover, coal mine methane is a clean burning fuel, and when coupled with cogeneration's efficiency, produces negligible SO_2 and NO_x emissions. For these reasons, independent power producers may find sites near coal mines attractive locations for new gas-fueled cogeneration facilities. In addition, if a coal mine uses steam to cool its buildings, the use of chloroflurocarbons (CFCs) and hydroflurochlorocarbons (HCFCs) could be eliminated, further reducing greenhouse gas emissions.

About 62% of today's cogeneration systems are fueled by gas

While conventional power generation systems operate at 25-45% efficiencies, cogeneration systems can boost efficiency over 80%, depending on the thermal energy use. Cogeneration plants can vary in size from 500 kW up to 500 MW, where systems that produce more heat have higher efficiencies. The ability to sell excess electricity and/or thermal energy makes cogeneration plants a cost-effective source of energy as well as a revenue-generating investment.



Schematic of a cogeneration facility located at a coal mine with a coal prep plant on site

Currently, independent power producers and turbine engineering manufacturing companies are capitalizing on the opportunities resulting from restructuring of the electric industry by filling the needs of companies that require both electrical power and thermal energy. As a result, standard, smaller, semi-mobile cogeneration systems that can supplement a coal mine's electrical and/or thermal needs could be an asset to most gassy coal mines. These packaged systems can be installed in less than two weeks, require little maintenance, and are designed for remote operation. Systems such as these generally range from 1-5 MW in size and installed costs range from $600 to $1000/kW, depending on site specific requirements. A typical coal mine could use a 1-5 MW cogeneration unit to generate electricity for on-site use or sale to other consumers. By self-generating electricity, the mine could avoid electricity purchase costs. In addition, the mine could use the thermal energy to heat and cool surface facilities, such as office buildings, maintenance shops or bath houses.

Power generation equipment vendors are developing small-scale, standard cogeneration systems for coal mine methane applications. One such factory-built system is a 3 MW gas-fueled power unit that can produce up to 3.5 MW of electricity (combined with a 0.5 MW steam turbine) and 30,000 pounds of process steam per hour. A second 4.5 MW combined-cycle system (3 MW gas turbine combined with a 1.5 MW steam turbine) is available for applications where there is little or no use for process steam. Energy efficiency decreases to 35-50%, however, when steam is not fully utilized. Several companies that market these standardized cogeneration systems prefer to own and operate them, and enter into partnerships with fuel suppliers and utilities. Under those circumstances, coal mines would not need the capital to establish a gas-fired power project. Most gassy coal mines drain enough methane required to fuel cogeneration projects of this size (approximately 0.5-1.5 mm cfd).

Typical Small-Scale Cogeneration Systems

Electricity Produced	Steam Produced	Steam Pressure	Maximum Fuel Use	System Efficiency	NO_x Emissions
1.5-4.5 MW	0-30,000 lbs per hour	50 to 420 psig	20-60 mm Btu/hour	50-75%	20-80 ppm

For More Information...

Coal mine operators can take full advantage of cogeneration systems by using them on site for heating or coal drying, or selling thermal energy to a nearby industry. Cogeneration provides low-cost power, steam for heating and cooling buildings, and when fueled by coal mine methane, reduced greenhouse gas emissions.

To obtain more information about converting coal mine methane into energy using cogeneration systems, contact:

Stephen K. Swinson
President
Technology Division
Trigen Energy Corporation
One Water Street
White Plains, NY 10601
(914) 286-6600
Fax: (914) 948-9157

To obtain general information about cogeneration, contact:

John Fiegel
International District Energy Association
1200 19th Street NW Suite 300
Washington, DC 20036
(202) 429-5111
Fax: (202) 429-5113

Or contact the EPA's Coalbed Methane Outreach Program for information about this and other profitable uses for coal mine methane:

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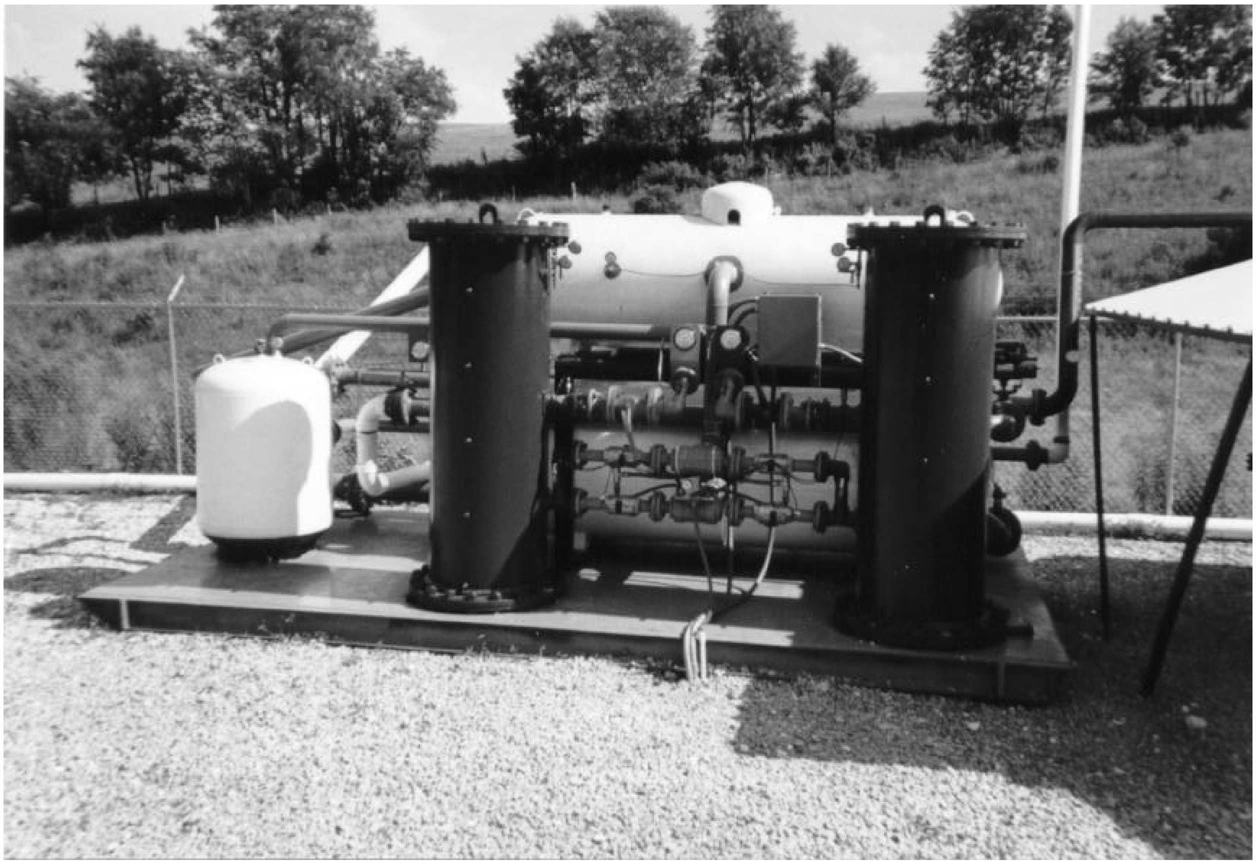
ENRICHMENT OF MEDIUM QUALITY COAL MINE GAS



Gas Enrichment Using Pressure Swing Adsorption at the Abandoned Nelms No. 1 Mine, Ohio
(Process development co-funded by Northwest Fuel Development, Inc. and U.S. DOE)

SOME FACTS CONCERNING ENRICHMENT OF MEDIUM QUALITY GAS...

- Technology for enriching gas containing as little as 50% methane is now feasible
- Coal mine gas enrichment can be profitable, especially for large projects
- Many mines have gob gas flows that would support financially attractive projects
- Recovery and use of gob gas reduces emissions of methane, a greenhouse gas

Gob gas enrichment requires rejection of nitrogen, oxygen, carbon dioxide, and water vapor

Why Consider Enrichment of Medium Quality Coal Mine Gas?

Gas drained from gob areas (collapsed rock over mined-out areas) typically contains 30-90 percent methane. Although gob gas is a potentially valuable fuel source, many mines vent it to the atmosphere, primarily because it does not meet quality specifications for injection into natural gas pipelines, which typically require a minimum of 95 percent methane. The coal mine methane industry has been searching for a proven and affordable solution to upgrading gob gas so they can take advantage of new markets now accessible through deregulation of the natural gas industry.

For years, enrichment facilities have been successfully upgrading medium-quality gas from natural gas wells, but none had been able to economically remove nitrogen, oxygen, carbon dioxide, and water vapor in the same integrated facility. Gob gas enrichment has made great progress in recent years, however, and a full-scale integrated gob gas enrichment project is currently in operation in Pennsylvania.

Gas processing vendors soon expect to offer integrated gob gas enrichment systems

In 1997, EPA's Coalbed Methane Outreach Program prepared a report titled *Technical and Economic Assessment of Potential to Upgrade Gob Gas to Pipeline Quality.* The report examined average costs that enrichment projects would incur in a typical mine setting for a variety of feed gas qualities and daily flows. The most critical and expensive component of any enrichment system is the nitrogen rejection unit (NRU). Suppliers of three major nitrogen rejection technologies affirm that a gob gas enrichment plant is technically feasible and free of unacceptable risks. Below is a brief overview of the major nitrogen rejection technologies whose suppliers are willing to make firm proposals for integrated enrichment plants.

Cryogenics Process. The cryogenics process pressurizes and flashes the feed gas stream and then uses a series of heat exchangers to liquefy the gas mixture. A distillation separator vents a nitrogen-rich stream, leaving the methane-rich stream. BCCK Engineering supplied the cryogenics technology used in the integrated gob gas enrichment project underway in Pennsylvania.

Pressure Swing Adsorption (PSA) systems repeatedly pressurize the gob gas and use various adsorbents to selectively adsorb nitrogen and methane in different concentrations and/or rates. During successive cycles, the process preferentially adsorbs methane in favor of nitrogen until the output attains the desired methane proportion. BOC Gases demonstrated a PSA process on gob gas and reported good methane recovery; however, in order to achieve the required gas quality, it was necessary to use feed rates lower than the nominal rating of the system.

At natural gas prices of $2.00 per mmBtu, enrichment projects that sell upgraded gob gas may be cost-effective if feed gas is available in flows of 5 mmcf/d or higher

Selective absorption uses specific solvents that have different absorption capacities with respect to different gas species. The petroleum refining industry commonly uses this method to enrich gas streams. One firm that offers selective absorption to reject nitrogen from methane, Advanced Extraction Technologies, is ready to offer the system to interested mine owners.

Other nitrogen rejection technologies are under development, as discussed on the following page.

Key Conclusions from *Technical and Economic Assessment of Potential to Upgrade Gob Gas to Pipeline Quality*...

EPA's report included a technical assessment of cryogenic, PSA, and selective absorption NRU processes as the key components of their respective integrated gob gas enrichment facilities. The report also estimated capital and operating costs for a range of feed gas flows (3-6 mmcf/d) and qualities (50-90%). Following is a summary of some of the report's key findings:

- All of the three nitrogen rejection techniques evaluated could successfully operate as the principal component of an integrated plant to enrich gob gas. In some instances, a cryogenics unit could be risky, given the presence of oxygen and carbon dioxide and the compositional and flow rate variations inherent with gob gas. In the selective absorption process, oxygen removal must be the first step. Systems that carry oxygen through the process units (such as PSA) would have to provide designs that remove the risk of explosion in certain combinations of oxygen and methane.

- Several companies are developing other nitrogen rejection technologies that are potentially applicable to an integrated gob gas cleanup system. These include alternative PSA systems (improved adsorbents, continuous PSA), alternative absorption technologies, and membrane units. Northwest Fuel Development Inc. has successfully demonstrated both PSA and CPSA nitrogen rejection units at the Nelms Mine in Ohio (see cover photo). These systems appear to be economic with flow rates as low as 1 mmcf/d.

> *Enrichment may work well with a broader, integrated strategy that includes one or more of the following: 1) improving gas recovery systems to enhance gas quality; 2) blending gob gas with higher quality gas; and 3) spiking gob gas with propane. EPA has prepared a user-friendly computer program that helps gas project developers identify cost-effective combinations of these various upgrade options.*

- Enrichment projects that sell upgraded gob gas into the natural gas transmission or distribution market may be cost-effective relative to current natural gas prices if 80% methane feed gas is consistently available in daily gas flows of 5 mmcf/d or higher. This conclusion is based on conservative estimates of capital and operating costs for typical plants operating under an assumed set of conditions.

COMPARISON OF NITROGEN REJECTION ENRICHMENT UNITS IN INTEGRATED SYSTEMS

Vendor	*UOP*	*Nitrotec*	*BOC*	*AET*	*Darnell*	*Schedule A*
Technology	PSA*	PSA	PSA	Selective Absorption	Cryogenic	Cryogenic
Phase Change	No	No	No	No	Liquefy	Liquefy
Methane Recovery	Up to 95%	Up to 95%	98%	96-98%	98%	98%
First Stage Deoxygenation	No	No	No	Yes	Yes	Yes
Ready to design and build an integrated gob gas plant?	Yes	Yes	Yes, possibly	Yes	Yes	Yes, after trials
Vendor list is not complete; includes only vendors that supplied technical and cost details of their systems. Contact information for these and other suppliers is available in the EPA report described above. Minimum plant size available from most vendors is 3 mmcf/day of feed gas; all are capable of processing at least 6 mmcf/day of feed gas.						

For More Information...

The EPA report *Technical and Economic Assessment of Potential to Upgrade Gob Gas to Pipeline Quality* provides more detailed information on enrichment technologies and average costs that enrichment projects would incur.

To obtain a copy of the report, and a computer program that helps gas project developers identify cost-effective combinations of enrichment, blending, and spiking options, contact:

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401 M Street, SW (6202J)
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COAL MINE METHANE USE IN FUEL CELLS

200 kW Phosphoric-acid fuel cell (PAFC) with a thermal output of 700,000 Btu/hr
Unit dimensions = 10ft x 10ft x 18ft. (Photo courtesy of International Fuel Cells)

COAL MINE METHANE POWERED FUEL CELLS CAN...

- Operate on methane from mine pre-drainage and medium quality gob gas
- Use methane at near atmospheric pressure, avoiding compression costs
- Use methane diluted with air and/or carbon dioxide
- Generate electricity for distributed power generation systems
- Lower NO_X and SO_2 emissions, and virtually eliminate particulate emissions
- Reduce emissions of methane (a greenhouse gas)

Coal mine methane can be used in fuel cells to generate low cost power for mining operations, trimming overhead costs

WHY CONSIDER COAL MINE METHANE POWERED FUEL CELLS?

At present, fuel cells are economically competitive with conventional forms of electricity generation only in certain cases. Fuel cells are, however, making steady progress toward the goal of widespread commercial use. Use of methane in fuel cells, recovered from gassy coal mines, may be an economical approach to on-site power generation or local use.

Gob areas (collapsed rock over mined-out areas) release large volumes of gas and subsequently vent it to the atmosphere. Much of this gas is of medium quality and unsuitable for pipeline injection. However, fuel cells can operate on medium-quality gas, reducing methane emissions to the atmosphere while producing electrical power for on-site use. Because of their high efficiency, the use of fuel cells for power generation emits less carbon dioxide per kilowatt-hour of electricity produced than conventional turbine and internal combustion power generation methods. Sulfur and NO_x emissions are also low, making permitting easier and less expensive.

Powering fuel cells with coal mine methane provides economic benefits, as well as the environmental benefits already associated with fuel cells

Several hundred phosphoric-acid fuel cells (PAFCs) are now in use worldwide. In the United States, several small commercial and light industrial operations have begun using PAFCs during the past five years. PAFCs are reliable and can operate on conventional natural gas as well as coal mine methane. PAFCs that produce from 200 kW to 11 MW at 40 percent efficiency are now commercially available from International Fuel Cells.

Molten-carbonate fuel cells (MCFCs) are smaller than PAFCs, and testing indicates that they are more efficient. The US Department of Energy, in conjunction with the City of Santa Clara, has successfully tested MCFCs with a capacity of 200 kW to 2 MW. The U.S. Department of Energy plans to test MCFCs using gas produced from coal gasification, and coal mine gob gas. Commercial versions of these fuel cells should be available by 2001.

SOME FACTS ABOUT POWER GENERATION USING FUEL CELLS...

- Modular design allows for custom power generation and generation close to the load, reducing transmission and distribution losses
- Better efficiency than turbine generated power (efficiencies between 40-60%)
- A typical gassy mine can drain at least 1 mmcf of methane per day. A 200 kW PAFC unit would require about 80 mcf per day of medium heating value (50% methane) gas; a MCFC would require about 62 mcf per day
- Ideal power for industries located near coal mines producing medium to high heating value coal mine gas
- Short permitting and licensing schedules due to clean, quiet, safe operation
- Capable of using thermal output for heating (cogeneration), raising potential efficiency to over 80 percent
- Main by-product is purified water

Coal mine methane lacks heavy hydrocarbons, making it better suited to fuel cell power production than natural gas

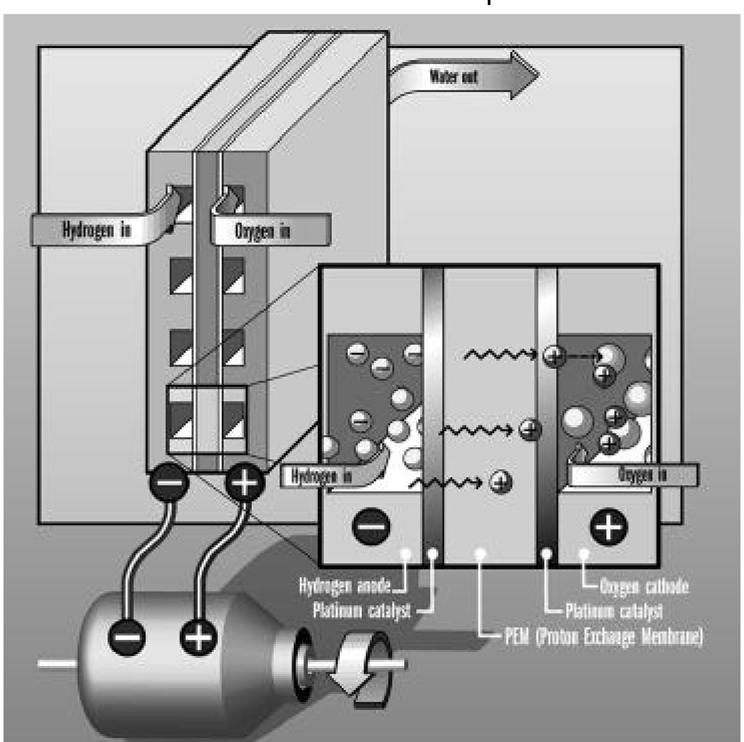
COMPARISON OF PHOSPHORIC ACID AND MOLTEN CARBONATE FUEL CELLS

Parameter	*Phosphoric-acid Fuel Cells (PAFC)*	*Molten-carbonate Fuel Cells (MCFC)*
Typical operating costs ($US)	$0.0017/kWh	$9.8/kW/yr + $0.0017/kWh[1]
Typical capital costs ($US)	$2,250-3,750/kW	$1,000-1,500/kW[1]
Estimated total costs/kWh ($US)[2]	$0.0527-0.0873/kWh	$0.0256-0.0370/kWh
Typical efficiency	40-45%	50-60%
Operating temperature (°C)	200	650
Thermal output (Btu/kWh)	7,000-8,300	6,000-6,800
Oxidant requirements	Oxygen	Oxygen & Carbon dioxide[3]
Can use coal mine methane[4]	Yes	Yes
Fuel processor required	Yes	No
Commercial availability	Now	2001

[1]Estimated for commercial operation when available.
[2]Based on a 200 kW unit over a five year operation period at maximum capacity. Five years is the minimum expected life for the cell stacks. Technology is evolving rapidly and prices are expected to decrease.
[3]Fuel cells can use air as an oxygen source. Product gas can be a source of carbon dioxide.
[4]Either coal mining operations or "stand-alone" wells can provide coalbed methane for the process. Utilization of methane produced during coal mining operations is especially attractive because in most cases, mines vent the methane to the atmosphere, which contributes to global warming. Because mines would otherwise waste coal mine methane, it is typically less expensive than conventional natural gas.

USING COAL MINE METHANE IN FUEL CELL-POWERED VEHICLES

Proton exchange membrane (PEM) fuel cell technology has been refined during the past few years and used in a wide range of stationary and transportation applications. Since 1997, several urban transit buses in Vancouver, British Columbia and Chicago, Illinois have been powered by 275 HP Ballard Fuel Cell engines. These zero-emission engines use hydrogen reformed from natural gas or methanol to create electricity without combustion. The Fuelcell Propulsion Institute is currently developing fuel cells powered by hydrogen produced from coal mine methane for use in underground mine vehicles. Coal mine methane can play a key role in the production of hydrogen to fuel both stationary fuel cell power plants and fuel cell engines for vehicles.



How A Proton Exchange Membrane Fuel Cell Works

The underlying principle of the fuel cell is similar to that of a battery. Operating with a solid electrolyte at low temperature of approximately 80°C, hydrogen (H_2) and oxygen (O_2) are fed into the cell and an electrochemical reaction generates direct current. The only reaction product is water (H_2O).

For More Information...

Recent developments in fuel cell technology are expanding the options for coal mine methane use. Use of coal mine methane in fuel cells can increase mine profits while reducing methane emissions to the atmosphere.

To obtain more information about using coalbed methane in fuel cells for power generation, contact:

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Energy Research Corporation
1634 Eye Street Northwest
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Fred S. Kemp
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Or contact U.S. EPA's Coalbed Methane Outreach Program for information about this and other profitable uses for coal mine methane:

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USE OF COAL MINE METHANE IN GREENHOUSES

Greenhouse facility near Harrisburg, Illinois grows hydroponic tomatoes and cucumbers
(Coal mine methane-fueled cogeneration system produces on-site electricity and thermal heat)

PROFITABLE OPPORTUNITIES FOR GREENHOUSE AND MINE OPERATORS

GREENHOUSES CAN...

- Use methane from coal mine pre-drainage and gob wells as a heating fuel
- Use electricity generated on-site or nearby from coal mine methane
- Use CO_2-enriched coal mine ventilation air to maintain consistent temperatures and stimulate plant growth
- Use coal mine wastewater for irrigation at some locations

Why Consider Using Coal Mine Methane in Greenhouses?

Depending on negotiations, coal mine methane can be cheaper than conventional natural gas for heating

Many coal mines in the United States and other countries emit high volumes of methane. In the U.S., these volumes may range from less than 0.5 million cubic feet per day (mmcf/d) to more than 10 mmcf/d. Greenhouses can use coal mine methane to meet their energy requirements. Several gassy mines in the United States are capable of meeting the heating and electricity requirements that most greenhouses have. A mine can usually sell methane at a negotiated price that is lower than what the greenhouse would pay for conventional natural gas or other fuels. As a result, greenhouses can reduce their operating costs, while the mine benefits from sale of the methane.

In southern Illinois, Grayson Hill Farms, Inc. operates a greenhouse that uses methane from a nearby abandoned coal mine to produce electricity and thermal heat for growing tomatoes and cucumbers. Three Ford and International truck engines produce 75-80 kW of electricity each, enough power to meet all the electricity needs of the greenhouse. Excess electricity up to 50 kW is sold back to a utility company via the local grid. In addition, the cogeneration power system uses exhaust heat from the engines to produce hot water for the greenhouse's heat-radiant floors. Methane from the mine is also used to fuel gas heaters and CO_2 generators inside the greenhouse.

The cost of producing electricity on site using coal mine methane could be as low as $0.03 per kWh, which is typically less than commercial power rates

While the primary driving forces for locating greenhouse operations near gassy coal mines are the potential net energy savings for the use of methane for heating and/or electricity production, there may be secondary financial benefits as well. One secondary benefit is the potential for use of mine ventilation air in a greenhouse to help stimulate plant growth. Ventilation air is rich in CO_2 (2,000-3,000 ppm in ventilation air as compared to 300-400 ppm in the atmosphere). Ventilation air also remains at a fairly constant temperature year-round, which can help maintain consistent greenhouse temperatures. Another potential benefit is the use of mine wastewater for irrigation purposes in cases where the quality of this water is suitable for greenhouse needs.

Benefits for Greenhouses, Coal Mine Operators, and the Environment ...

- **New Markets.** Coal mines need a market for their methane, and greenhouses have a large energy demand.
- **Lower Prices.** In many cases, gassy coal mines can supply methane to a greenhouse at a lower cost than commercial retail gas or electricity prices.
- **Increased Revenue.** Coal mine operators gain additional, stable revenue sources.
- **Reduced Costs.** The greenhouse operator would benefit from reduced energy costs, water, and CO_2.
- **Environmental.** Use of coal mine methane protects the global environment by reducing emissions of methane, a greenhouse gas, to the atmosphere.

Some greenhouses have been able to reduce heating costs by 87% using mine ventilation air to modify greenhouse temperatures

Key Factors Affecting Coal Mine/Greenhouse Project Economics...

- For a project to be economic, the mine must generally be able to recover at least 0.3 mmcf/d of methane
- Greenhouses with electricity needs of at least 5 million kWh/year and heating needs of at least 100 billion BTUs/year will be good candidates
- Projects with smaller greenhouses can be profitable given certain site-specific and market conditions (e.g., high electricity rates, cold climate, and high water costs)
- Locating the greenhouses close to the mine can minimize fuel transport costs

Additional information on this topic can be found in the EPA report, *Making Coal Mine Methane Work for You: A Guide to Coal Mine/Greenhouse Projects*, November 1998.

For More Information...

Greenhouse operators are seeking ways to improve economics by reducing fuel costs. Meanwhile, increasing numbers of coal mine operators are initiating methane recovery projects in an effort to increase mine safety and productivity, as well as gain additional revenues from methane sales. The use of coal mine methane in greenhouses can provide financial benefits to both parties.

EPA is analyzing the economic and financial benefits of coal mine methane use in greenhouses. For more information about this and other profitable uses for coal mine methane, contact:

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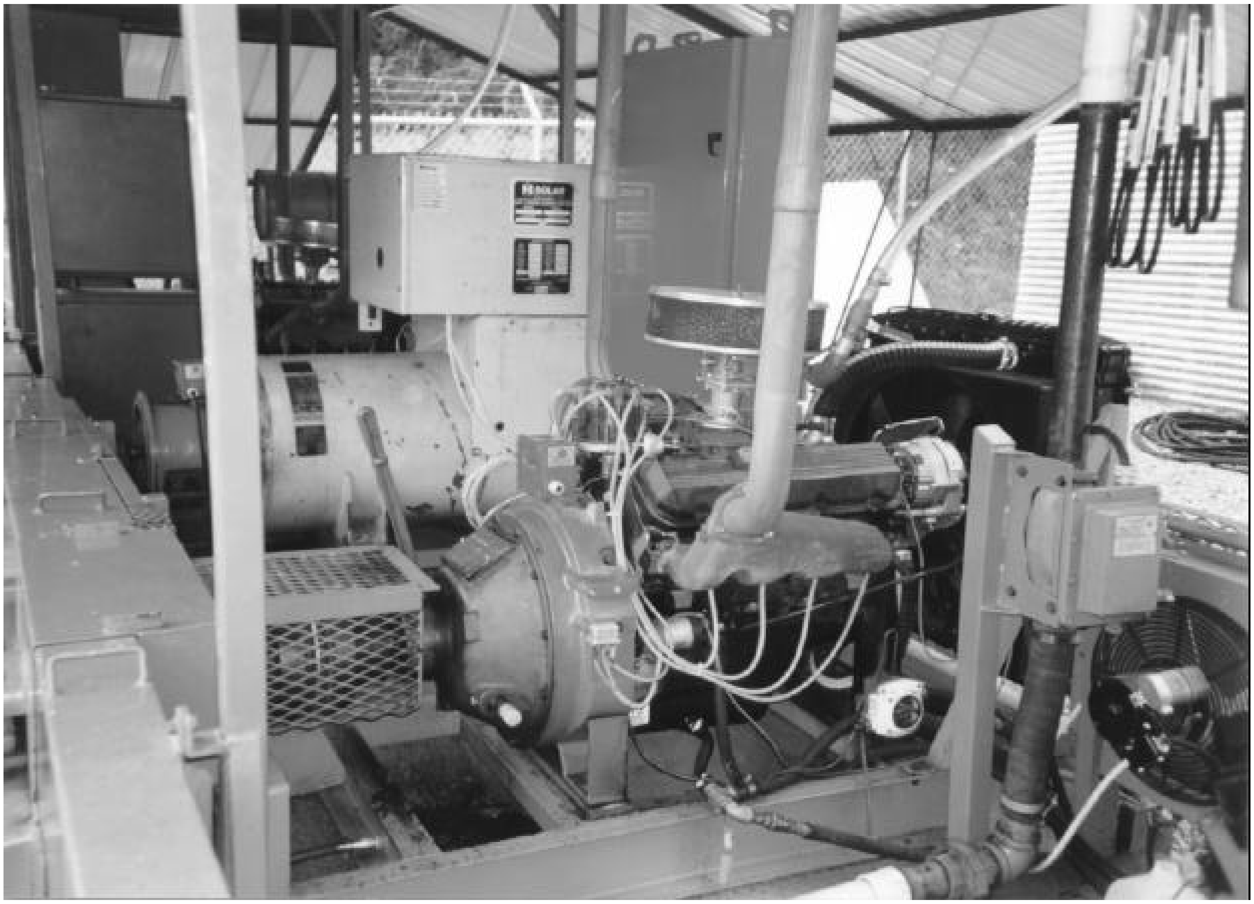
USE OF COAL MINE METHANE IN IC ENGINES AT COAL MINES



225 kW Synchronous Skid-Mounted Generator at Nelms No. 1 Mine, Ohio
(Photo courtesy Northwest Fuel Development, Inc. and U.S. DOE)

A PRACTICAL APPROACH TO POWER GENERATION AT COAL MINES...

- Economic benefits to coal mines, power producers and end users
- Improved on-site power supply reliability
- Modular design accommodates fluctuations in gas supply
- Commercially proven at the Nelms No. 1 Mine, Ohio, USA and at the Appin and Tower Collieries, New South Wales, Australia
- Reduces emissions of coal mine methane, a greenhouse gas

Why Consider Using Coal Mine Methane in IC Engines?

IC engines operate on gas at atmospheric pressure; they do not require compressed fuels like gas turbines

Mining of underground coal deposits releases large quantities of methane gas, which presents a safety hazard to miners and therefore must be ventilated or removed. Mines can drain methane ahead of mining operations through the drilling of vertical wells in the surrounding coal seam. Vertical wells usually produce high quality gas, (over 90% methane concentration) with a heating value of over 900 Btu/cf. In contrast, gob wells (drilled into collapsed rock over mined-out areas) produce medium quality gas that generally contains 30-80% methane.

Most methane recovery operations inject pipeline quality gas directly into a pipeline and sell it to utility companies. Mines often vent the medium quality gas they drain from gob wells into the atmosphere instead of using it, because gob gas requires enrichment prior to pipeline injection. However, fuel for power generators does not require pipeline quality gas. Generally, IC engines can be adapted to generate electricity using coal mine gas with a methane concentration as low as 20%. (For safety reasons, however, mines usually cease production of gob gas if the methane concentration drops below 25%).

In Ohio, Northwest Fuel Development, Inc. (NW Fuel), with the assistance of the U.S. DOE, has developed power generators that use medium quality gas. The "prime mover" in NW Fuel's power generating set is a 100 hp IC engine manufactured by General Motors. Properly configured carburetors in this light truck engine allow for the use of fuels ranging from 20% to 100% methane. The engines generally provide service for over 12,000 hours (or one and one-half years) before any significant maintenance is required. After maintenance, the engines are placed back in service for another 8,000 to 10,000 hours before they are replaced.

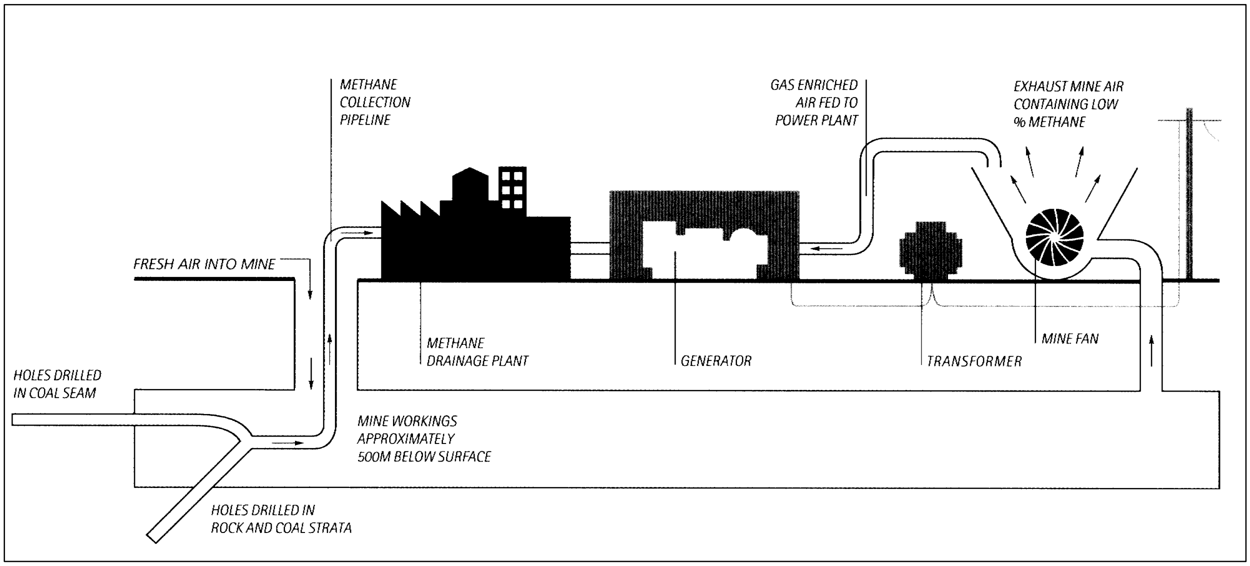
Maintenance and parts for IC engines are readily available

NW Fuel recovers methane from the Nelms Mine No. 1 and generates power for on-site use at the neighboring Nelms Cadiz Portal Mine. Through the use of common mass-produced GM engines, the power-generating equipment developed at the Nelms Mines produces low-cost electricity by keeping capital and operating costs to a minimum. Currently, the project also sells some electricity directly to American Electric Power Company, a local utility.

SOME FACTS ABOUT POWER GENERATION AT THE NELMS COAL MINES...

- Current nine-unit system capable of generating 675 kW of electricity
- System uses about 225,000 cubic feet of coal mine methane per day
- Existing units produce three-phase electricity at 480 volts
- Installed costs of generator sets and utility-required protective relays are less than $800/kW
- Produce power for less than $0.025/kW-hr

IC engines operate on gas at atmospheric pressure; they do not require compressed gas like gas turbines



Use of methane at the Appin Colliery for power generation in IC engines
(Schematic courtesy of Energy Developments, Ltd.)

On a larger scale, Energy Developments Ltd. (EDL) has developed a power project in Australia that uses coal mine methane (supplied by BHP's Appin and Tower Collieries) to generate electricity for the local utility grid. The project cuts the mines' methane emissions in half and delivers a total of 94 MW of power to the utility grid during peak demand hours. Of this, 4-10 MW is fed back from the utility grid to meet the mines' equipment energy requirements, such as ventilation fans, power equipment, and other critical loads. The remaining power is supplied to Integral Energy Australia. By purchasing power from this project, Integral Energy, a local distribution company and energy trader, expects to save its customers more than $US 2.4 million annually. To ensure consistent gas quality and quantity, EDL uses an electronic monitoring and control system to supplement the coal mine gas with natural gas when necessary.

As with the Nelms Mines, this innovative project converts coal mine methane to electricity using a conventional internal combustion engine. In this case, a 16-cylinder Caterpillar G3516 bulldozer engine is connected to a Cat SR4 brushless generator. Housed in soundproof sheds, the 94 generator sets convert over 20 million cu ft/day of coal mine methane to 94 MW of electricity. Each generator set is expected to operate up to 8000 hours a year. A gas turbine-based system was not considered as cost-effective because of the need to compress the gas before fueling, and because experience had shown that maintenance could be a problem at the site.

Some Facts About the Use of IC engines at the Appin Power Project...

- Each engine directly drives one 415 volt 1 megawatt generator
- Fuel gas composition varies from 50 - 85% methane, 0-5% $C0_2$, and up to 50% air
- Modular design provides for off-site fabrication, ease of relocation, and staged expansion
- Mine ventilation air from Appin Colliery, containing 0.5 -1.0% methane, supplies all of the combustion air to the 54 units at the Appin plant (mine design prohibits this option at Tower)

For More Information...

The economic success at the Nelms Mines in Ohio and the Appin and Tower Collieries in Australia is prompting coal and electricity producers worldwide to take a new look at using methane-fueled internal combustion engines for power generation. This approach has the added benefit of reducing methane emissions by converting a waste product into electricity.

To obtain more information about using coalbed methane in gas engines, contact:

Mr. William Lazarus
General Manager
Energy Developments, Ltd.
P.O. Box 535
Richlands, QLD
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Tel: (61) (7) 3275 5555
Fax: (61) (7) 3217 0733

Dr. Peet Sööt
Northwest Fuel Development, Inc.
4064 Orchard Drive
Lake Oswego, OR 97035
Tel: (503) 699-9836
Fax: (503) 699-9847

Or contact the EPA's Coalbed Methane Outreach Program for information about this and other profitable uses for coal mine methane:

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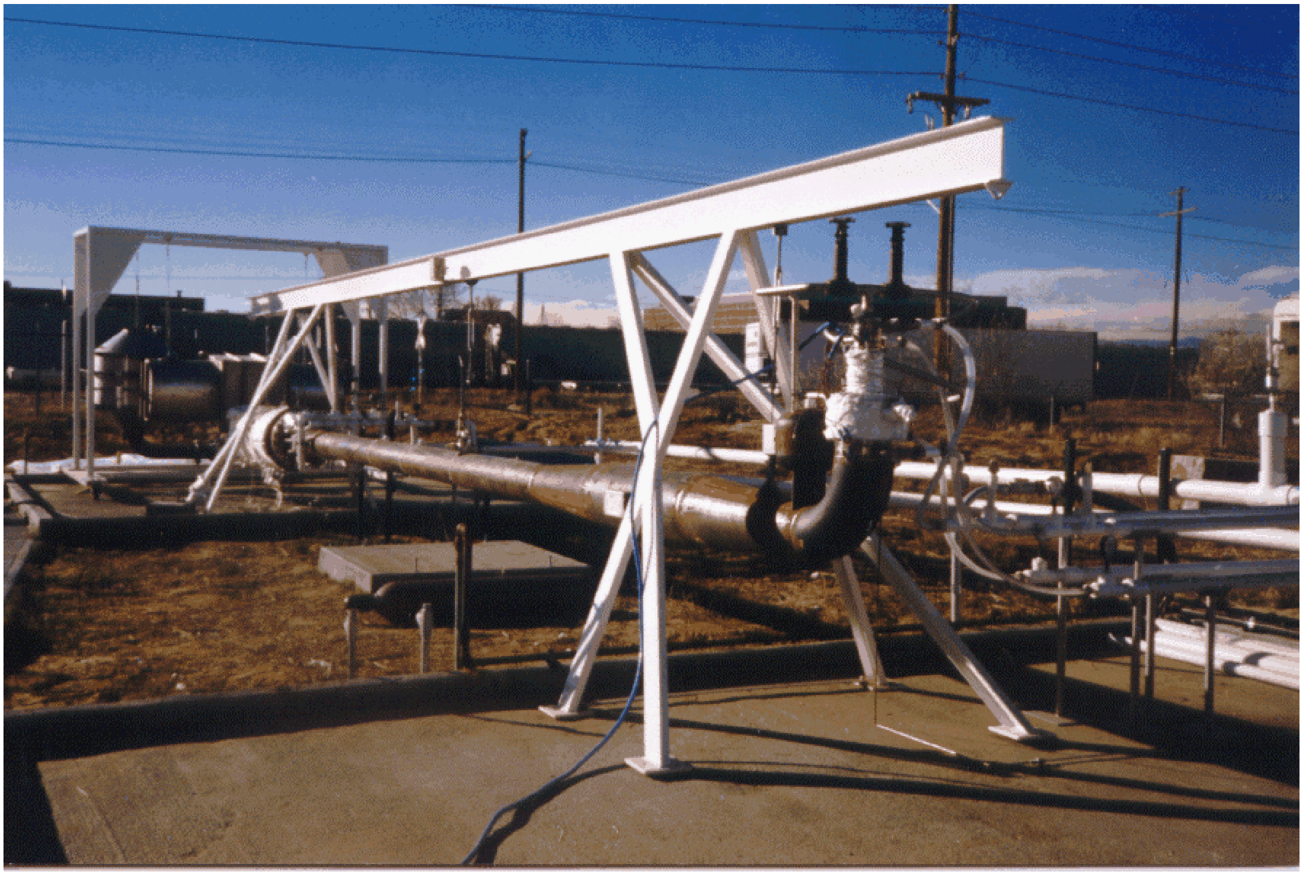
COAL MINE METHANE AND LNG



100 gallon per day prototype Thermoacoustically Driven Orifice Pulse Tube Refrigerator
(Photo courtesy of Cryenco, Incorporated)

PRIMARY BENEFITS OF USING COAL MINE METHANE FOR PRODUCING LNG...

- Can operate on methane from mine pre-drainage and medium quality gob gas
- Uses methane at near atmospheric pressure, avoiding compression costs
- Can use methane diluted with up to 20 percent nitrogen
- Reduces emissions of methane (a potent greenhouse gas)
- Highly mobile system can be located near methane collection site

Small-scale LNG units can use coal mine methane from production wells or medium quality gob gas

WHY CONSIDER COAL MINE METHANE FOR LIQUIFIED NATURAL GAS?

As liquified natural gas (LNG) producers compete for growing markets, they are seeking ways to cut production costs. LNG plants have traditionally been large, elaborate, and expensive. Smaller facilities are now becoming economic, creating new opportunities in the form of both non-traditional markets and non-traditional gas sources.

Coal mine methane may prove to be a low-cost alternative to conventional natural gas for LNG production in some areas. Gob areas (collapsed rock over mined-out areas) release large quantities of gas, which mines remove with ventilation fans, sometimes supplemented by drainage systems. Air from mine ventilation contaminates the gob gas, usually making it unsuitable for pipeline injection. However, recovering and using gob gas to make LNG can reduce the amount of methane that mines emit to the atmosphere while producing inexpensive fuel for mine vehicles, machinery, heating, or other local uses.

Traditionally, LNG production has been limited to very large operations located near natural gas pipelines. Small-scale refrigeration techniques have succeeded in efficiently downsizing gas liquefaction units so that they are portable and inexpensive. Instead of compressing gas mechanically, these units use acoustic power to compress and expand a working fluid (normally helium), dissipating heat through exchangers. A linear motor or thermoacoustic driver in a tube generates the acoustic power.

Acoustic LNG compression units are highly portable making them ideal for remote locations

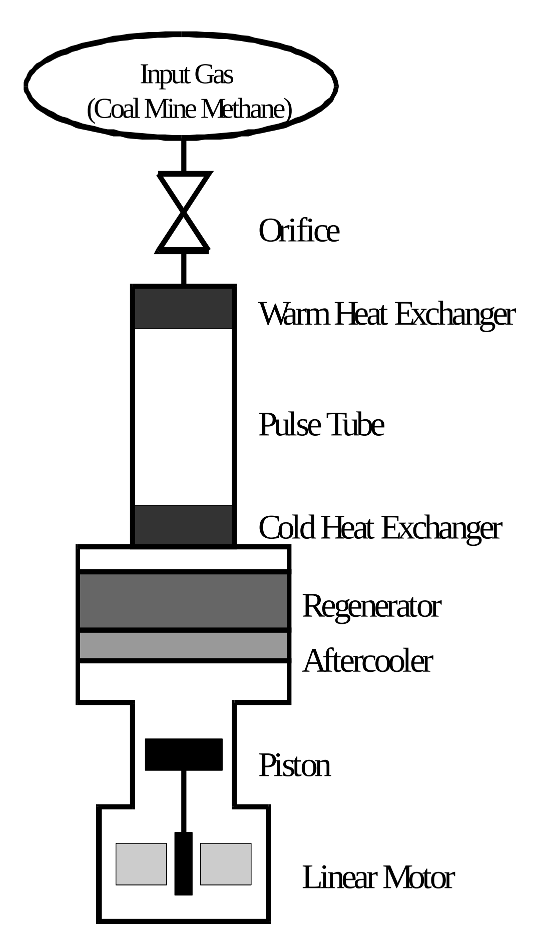
The smallest acoustic liquifaction process is Linear Motor Driven Orifice Pulse Tube Refrigeration. These units are available in a range of sizes, with output ranging from less than 10 gallons of LNG per day to several hundred gallons per day. The units are from 40-400 pounds and one to five cubic feet in volume, depending on the capacity. Linear motor drivers use flexure bearings that have no wearing surfaces, reducing maintenance costs. Efficiencies for these units can reach 85 percent.

Larger, but still portable, is the Thermoacoustically Driven Orifice Pulse Tube Refrigeration unit. Los Alamos National Laboratories and the National Institute of Standards and Technology first developed this technology in 1989. The thermoacoustic process uses a temperature gradient of 1640º F along the length of the unit to generate an acoustic wave. Prototypes have successfully produced 500 gallons of LNG per day at 70 percent efficiency. Cryenco, Incorporated projects that a commercial unit that will produce between 10,000 and 12,000 gallons LNG per day at approximately 80 percent efficiency will be available in 1999.

SOME FACTS ABOUT SMALL SCALE LNG PROCESSES...

- Some units require as little as 3 thousand cubic feet/day (mcfd) of medium quality gas to efficiently produce LNG on site
- 100 scf of methane can produce between 0.7 and 1.0 gal of LNG (59,000-85,000 Btu)
- Small LNG compression units weigh as little as 40 pounds
- Gas quality as low as 800 Btu is acceptable
- Ideal for remote collection sites where pipeline is not available
- Operate at 70-85 percent efficiency

Mines that produce LNG on site using gob gas can use it to operate mine vehicles and equipment, or may sell to a local consumer



Linear Motor Driven Orifice Pulse Refrigeration Compressor Schematic

CURRENT MARKETS FOR LNG

Worldwide, the largest market for LNG is fuel for electric power plants. The international gas association, Cedigaz, projects that the volume of LNG traded internationally could grow between 80% to 170% by the year 2005. The bulk of this growth is expected to occur in Asia, including nations such as China and India that have abundant coal mine methane resources. As a result, the expanding LNG market in Asia offers opportunities for coal mine gas use.

LNG is becoming increasingly popular as an alternative fuel for vehicles. Vehicles can store more liquid gas than compressed gas, making it well-suited for high fuel comsumption vehicles, including underground coal mine vehicles. In addition, substantial federal and state gas tax credits are available in the U.S. for converting and using alternative fuel vehicles.

One emerging use of LNG in North America is for seasonal gas storage. LNG plants, also called peak shaving plants, store natural gas during the warmer months, then vaporize and inject the gas into local pipelines during cold weather months. LNG plants could help the economics of coal mine methane projects in areas where other gas storage options are limited.

COMPARISON OF LNG COMPRESSION TYPES THAT COULD USE COAL MINE METHANE

PARAMETER	CONVENTIONAL PROCESS COMPRESSOR	LINEAR MOTOR DRIVEN	THERMO-ACOUSTICALLY DRIVEN
Typical output capacity (Gallons/day)	500	10-500	500-10,000[1]
Typical input capacity (Mcfd)	60-70	1-50	50-1,200
Typical dimensions (cubic feet)	100	1-5	4,000
Wearing parts	Yes	No	No
Typical cost ($US/Mcfd capacity)	9,000-10,500	3,800-7,400	1,500-5,100
Typical cost ($US/gal/day capacity)	500	250-500	100-300
Can use coal mine methane[2]	Yes	Yes	Yes
Commercial availability	Now	Late 1998	1999

[1]Estimated for commercial operation when available.
[2]Either coal mining operations or "stand-alone" wells can provide coalbed methane for the process. Utilization of the methane that coal mining operations produce is especially attractive because in most cases, the mines vent this methane to the atmosphere. This “waste gas” is a valuable fuel if mines use it; otherwise it is a potent greenhouse gas.

For More Information...

New technologies for liquifying natural gas are expanding the options for using methane recovered from coal mines. Use of LNG derived from coal mine methane can increase mine profits while reducing methane emissions to the atmosphere.

To obtain more information about technologies for liquifying coal mine methane or conventional natural gas, contact:

John J. Wollan
Acoustic Liquefaction Program Director
Cryenco, Incorporated
3811 Joliet Street
Denver, CO 80239 USA
(303) 373-3247
Fax: (303) 371-0267
e-mail: johnw@cryenco.com

Or contact EPA's Coalbed Methane Outreach Program for information about this and other profitable uses for coal mine methane:

Coalbed Methane Outreach Program
U.S. EPA (6202J)
401 M Street, SW (6202J)
Washington, DC 20460 USA
(202) 564-9468 or (202) 564-9481
Fax: (202) 565-2077
e-mail:fernandez.roger@epa.gov
schultz.karl@epa.gov

http://www.epa.gov/coalbed

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EPA Coalbed Methane Outreach Program Technical Options Series

GENERATING ELECTRICITY WITH COAL MINE METHANE-FUELED MICRO TURBINES

TurboGenerator™ Power System, photo courtesy of AlliedSignal

MicroTurbine™, photo courtesy of Capstone

Micro turbines are about a third the size of comparable diesel generators

APPLICATIONS AND BENEFITS INCLUDE...

- Off-grid self-generation of electricity at remote gas production sites
- Available in 30 kW to 2000 kW systems
- Use with cogeneration technologies such as discharge heat recovery
- Low air and noise emissions
- Low installation and maintenance costs
- Ideal for gob gas use, as they can operate on gas with a heating value as low as 350 Btu
- Recovery and use of methane reduces greenhouse gas emissions

Micro turbines have only one moving part, which drastically reduces maintenance

Why Consider Using Micro Turbines To Generate Electricity With Coal Mine Methane?

A large portion of the methane emitted from coal mines comes from gob areas (collapsed rock over mined out coal), where methane concentrations typically vary from 30 to 80%. Gas with a methane concentration less than 95% is usually not suitable for pipeline injection. Coal mines frequently do not use medium-quality gas from gob wells and instead vent the gas to the atmosphere, contributing to global warming. However, gas with a methane concentration exceeding 35% can in fact be used as a fuel for on-site electricity generation. Given their large energy requirements, coal mines can recover methane and generate electricity with micro turbines to realize significant economic savings and reduce greenhouse gas emissions.

The micro turbine is a new technology developed from the aerospace industry that may be an ideal option for on-site electricity generation at coal mines. The micro turbine consists of a small, air-cooled gas turbine connected to a high-speed generator and compressor on a single shaft. This simple design results in a system with a high power output, minimal noise generation, and efficient operation. Diesel, gasoline or kerosene can be used as alternate fuels to insure continuous electricity production in the event that the methane supply is disrupted.

Micro turbines use air-bearing technology that eliminates the need for lubricants

Micro turbines are a compact, quiet, clean, and reliable power source. Their compact size allows them to be located at remote gob well sites or inside mine buildings, and can reduce the level of investment and maintenance typically associated with conventional generators. Because the generating capacity can be sized from 30 kW to 2000 kW by integrating multiple-unit systems, a mine can easily scale the project according to its needs. The micro turbine's 22-30% efficiency rating improves with the use of exhaust heat for pre-heating and adsorptive cooling.

Currently, two manufacturers, Capstone Turbine Corp. and AlliedSignal Power Systems Inc. state that micro turbines will be available by late 1998. Advertised uses for micro turbines include off-grid power generation, load management, standby power generation, and cogeneration. According to projections from AlliedSignal and Capstone, installed costs for micro turbines will range from $US 350/kW to $700/kW.

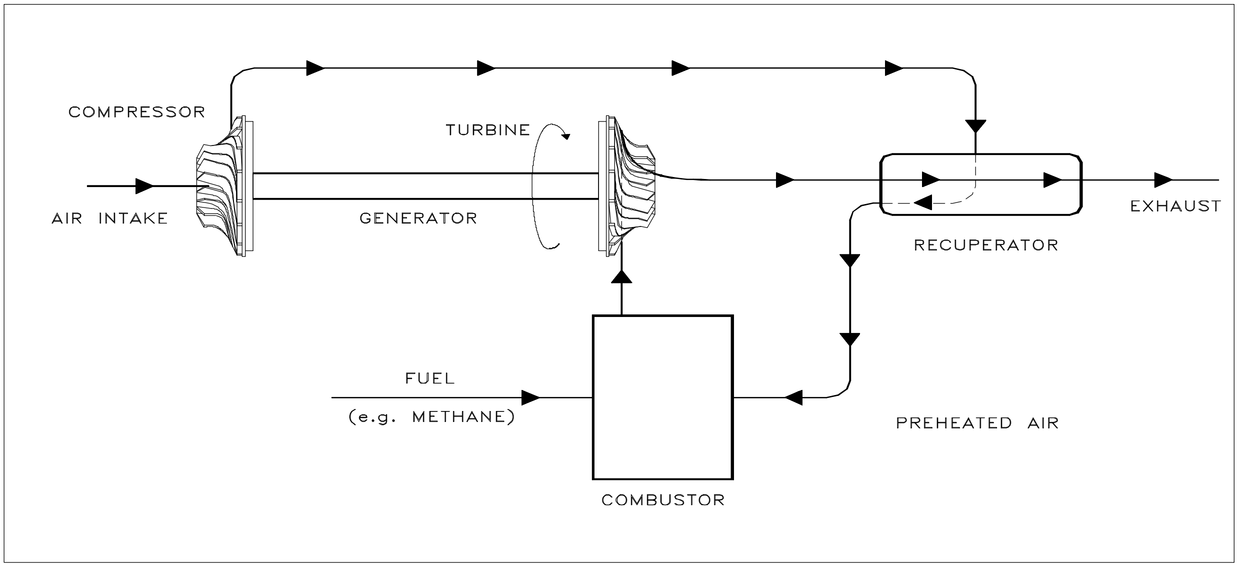
Facts About Micro Turbine Power Plants...

- Provide off-grid power to remote areas
- Exhaust temperatures for a single 30 kW system exceed 500^{o} F with an air flow of 35.2 lb (16.0 kg) per minute; a 75 kW system has a 470^{o} F exhaust temperature and an air flow of 91.2 lb (41.5 kg) per minute
- Mines can recover exhaust energy over 250,000 Btu/hr for heating or drying
- Quiet operation (at least one model is less than 60 decibels @ 33 feet)
- Multi-unit systems can be designed according to site-specific power demands
- Natural gas, diesel, gasoline or fuel oil can be used as a backup fuel

Micro turbines have a high power-to-weight and volume ratio compared to diesel generators

In today's changing power market, the trend toward distributed generation will allow consumers to determine their own power generation sources. At coal mines, these mini power plants can help shift the source of power from centralized power stations to on-site units, satisfying a host of power-generating needs. Micro turbines are both a short and long term solution to meeting a coal mine's electricity needs, while reducing greenhouse gas emissions.

HOW A MICRO TURBINE OPERATES



A micro turbine is a small, recuperated combustion turbine that operates with a high-speed generator, compressor and turbine located on the same shaft. Pressurized gas is preheated with turbine exhaust increasing the overall efficiency of the system. Benefiting from new technology, the core unit operates on floating air bearings eliminating the need for oil lubrication or cooling systems.

COMPARISON OF MICRO TURBINE WITH OTHER POWER GENERATION TECHNOLOGIES

	MICRO TURBINE	IC ENGINE	FUEL CELL	GAS TURBINE
Capacity (kW)	30-2000	10-4000	3-3000	1000-50000
Efficiency	22%-30%	12%-20%	40%-65%	21%-42%
Typical Installed Cost ($US/kW)	350-700	600-1000	900-3000	650-1000
Maintenance cost ($US/kW-h)	0.003-0.01	0.015-0.025	0.005-0.01	0.003-0.008

For More Information...

Rapidly changing electricity markets are creating new opportunities for on-site power generation using coal mine methane. Micro turbines may be a cost-effective power generation option for gassy underground coal mines.

To obtain more information about generating electricity using micro turbines contact:

AlliedSignal Power Systems Inc.
2525 W. 190th Street
Torrance, CA 90504-6099
Telephone: (800) 406-2267
Fax: (310) 512-1561
e-mail: turbogen@alliedsignal.com
Web site: www.alliedsignal.com/turbogen

Capstone Turbine Corp.
6025 Yolanda Avenue
Tarzana, CA 91356
Telephone: (818) 774-9600
Fax: (818) 774-0228
Web site: www.capstoneturbine.com

Or contact EPA's Coalbed Methane Outreach Program for information about this and other profitable uses for coal mine methane:

Coalbed Methane Outreach Program
U.S. EPA (6202J)
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EPA Coalbed Methane Outreach Program Technical Options Series

USING COAL MINE METHANE FOR HEATING MINE FACILITIES

The National Coal Museum in Illinois recovers methane from an abandoned coal mine to heat buildings

BENEFITS OF USING COAL MINE METHANE FOR SPACE AND WATER HEATING AT COAL MINES...

- Reduces costs by displacing other fuels that are used for heating
- Uses a fuel that is readily available at gassy coal mines
- Reduces emissions of methane, a greenhouse gas, to the atmosphere
- A profitable methane use option for mines with degasification systems in place

Use of coal mine methane on-site at gassy mines for space heating and/or water heating is potentially profitable

Why Consider Using Coal Mine Methane to Heat Mine Facilities?

Many gassy coal mines drain methane from their coal seams for safety reasons. While some mines recover and sell this methane, many mines simply vent it to the atmosphere unused. One potentially profitable option is to recover the methane and use it on-site to heat buildings and/or hot water. Most mines in the United States currently heat their surface facilities with natural gas, fuel oil (diesel), or propane. In some countries, it is common for coal mines to heat their facilities using coal-fired boilers. Coal mine methane may be a profitable alternative to other fuels, because it eliminates the cost of purchased fuel, or, in the case of coal-fired boilers, frees up coal for sale. Coal mine methane use is also beneficial to the environment, in that it reduces emissions of methane, a greenhouse gas, to the atmosphere.

The use of coal mine methane for this purpose is not new. Gassy coal mines in several countries (including China, the Czech Republic, Poland and Ukraine) use a portion of the methane they drain on-site for space and/or hot water heating. In such cases, the coal mine methane often replaces low-quality coal, and provides an economical, clean-burning alternative. The National Coal Museum in West Frankfort, Illinois recovers methane from the abandoned Orient No. 6 mine to heat restored mine buildings that are now used by a community college.

CMOP can provide the necessary technical and financial modeling support to coal companies interested in a site-specific analysis

Gassy coal mines that currently drain methane and wish to recover it for space and hot water heating would need to modify their heating systems. The most significant costs associated with these modifications will typically be the purchase of a compressor (to compress the gas for transportation from its production location to the building(s) to be heated) and installation of a pipeline. A mine that is already using natural gas, propane, or fuel oil to heat its buildings will also require minor modifications to the system. A mine that currently uses electricity or burns coal in a boiler would require more extensive modifications.

EPA Financial Analysis

EPA's Coalbed Methane Outreach Program (CMOP) prepared an analysis to illustrate the financial viability of using coal mine methane for heating surface facilities and hot water at active underground gassy coal mines. The analysis of any coal mine recovery project requires estimates of methane flow and availability at the mine. This case study builds on the following information:

Gas Availability and Use

For this illustration, the study assumes that the mine:

- produces an average of 4 million tons of coal each year;
- liberates 550 cubic feet of methane per ton of coal mined;
- currently uses propane, natural gas or fuel oil to heat its buildings;
- wishes to satisfy a heating demand of 10,000 million BTUs of fuel annually; and,
- can produce enough methane from an existing gob well to meet this demand (a least 11 million cubic feet per year)

Use of coal mine methane reduces emissions of this greenhouse gas to the atmosphere

Costs[1]

The study assumes that project costs are as follows:

- capital costs (skid mounted compressor, 1 mile of installed pipeline, engineering design, hot water system modifications) - $55,000
- estimated annual operating cost is $8,000

Financial Assumptions

[1]These are standard cost assumptions used in most first-order CMOP financial analyses of heating with coal mine methane

The analysis makes the following financial assumptions:

- the project will have a 20-year life;
- annual inflation rate is 4%;
- the real discount rate is 6%;
- the tax rate is 27.5%; and
- 100% equity project financing.

Results of the Analysis

Incremental benefits of this project are the annual savings realized from using recovered methane instead of purchasing fuel. The analysis computes incremental benefits based on a range of costs for purchased fuels. The following table lists the results of the analysis, showing that the project would be economically viable even when the cost of purchased fuel is unusually low.

Using Coal Mine Methane for Heating Mine Buildings and Hot Water

Scenario	Cost of Purchased Fuel* ($mmBtu)	Capital Cost ('$000)	Annual Cost ('$000)	NPV ('$000)	IRR (%)	Payback Years
1	$ 3.00	$ 55	$ 8	$ 134	35%	4
2	$ 5.00	$ 55	$ 8	$ 301	63%	2
3	$ 8.50	$ 55	$ 8	$ 592	111%	1

*To put these purchased fuel costs in perspective, following are typical purchase prices for various fuels, in $US per mmBtu: Natural gas - $4.75–5.75; Fuel Oil (Diesel) - $4.00-$5.00; Propane - $6.50-8.50; Electricity - $13.00-14.50.

The results of this analysis suggest that use of coal mine methane on-site for heating mine buildings and hot water at a gassy underground coal mine is a potentially profitable project option. To refine this analysis would require additional inputs such as actual gas content data, methane emissions data, and the cost of displaced fuel. CMOP can provide the necessary technical and financial modeling support to coal companies interested in a site-specific analysis.

Contact EPA's Coalbed Methane Outreach Program for information about this and other profitable uses for coal mine methane:

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COAL MINE METHANE USE IN METHANOL PRODUCTION

Sand Creek Chemical Plant in Commerce City, Colorado
(uses conventional natural gas to produce methanol)

A VIABLE SUBSTITUTE FOR CONVENTIONAL NATURAL GAS

- The methanol market is robust and growing worldwide
- Methane from coal mines often costs less than conventional natural gas
- The use of coal mine methane reduces greenhouse gas emissions

Why Consider Coal Mine Methane in Methanol Production?

Coal mine methane may be an attractive alternative to conventional natural gas for small methanol plants

Methanol is a key component of many products, including MTBE (used in reformulated gasoline), methanol and gasoline blends such as M85 for flexible fuel vehicles, formaldehyde resins (widely used in the housing industry), and acetic acid, a major raw material in the chemical industry. MTBE (the second largest methanol market, after formaldehyde) is the fastest growing segment of the methanol market worldwide, due to its value as a clean burning fuel additive. The United States is the world's largest MTBE user, consuming approximately 40% of all methanol used for MTBE production on a global basis. Most of the world's production of methanol uses natural gas as a feedstock, and natural gas typically represents the most important cost component. Many countries produce methanol, although production tends to be concentrated in areas where natural gas is abundant.

For safety reasons, gassy underground coal mines must drain methane from their coal seams. Most coal mines vent this methane to the atmosphere, which not only represents the loss of a valuable fuel source, but also contributes to global warming, as methane is a potent greenhouse gas. However, a growing number of mines in many parts of the world recover the drained methane for sale to pipelines, or for heat or electricity generation. To date, no methanol producers have used coalbed methane, but it is a potential alternative feedstock in areas that mine gassy coal. Coal mines do not produce enough methane to fuel large methanol plants, but one or more very gassy mines typically produce enough methane to fuel a small (25-30 million gallons/year) methanol plant. Alternatively, smaller (3-5 million gallons/year) mobile methanol plants currently used at offshore oil rigs may be a potential option for use at coal mines.

The cost of coal mine methane is often less than conventional natural gas

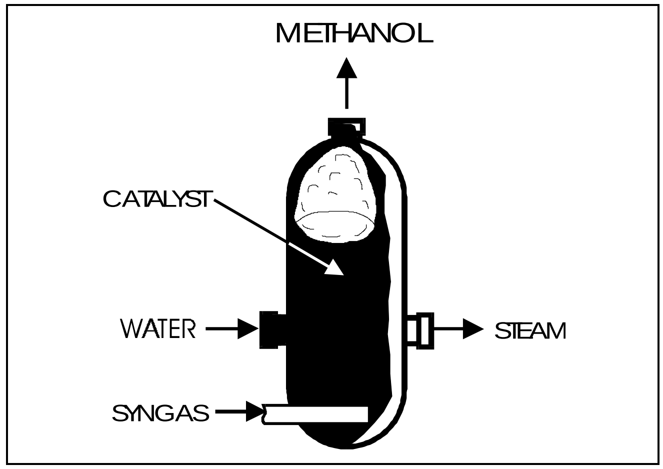
Some Facts About Methanol Production...

- 100 ft^3 (2.83 m^3) of methane will produce 1 gallon (3.8 liters) of methanol.
- Production costs are \$US 0.35-0.45/gallon (\$US 0.09/liter), assuming natural gas prices of \$2-\$3/mcf (\$0.70 - \$1.06/thousand m^3). At \$2/mcf, natural gas typically accounts for about half of production costs at small plants.
- Typical 1997 methanol prices are around \$US 0.55-0.70/gallon (\$US 0.15-0.18/liter). Methanol prices can be volatile.
- Gassy mines are often located near methanol markets, potentially reducing transportation costs.
- Small plants produce 25-30 million gallons (95-114 million liters) per year. Methane requirements for small plants range from 7-8 million ft^3 (200-226 thousand m^3) per day.
- Startup costs for a small plant are about \$US 1.33 million per million gallons of annual plant capacity (\$US 40 million for a 30 million gallon/yr plant).
- Gas quality should be at least 89% methane; up to 1% oxygen; and up to 10% CO_2 (a small amount of CO_2 is actually beneficial).

The market for methanol is increasing worldwide

How is Methane Converted to Methanol?

The first step in producing methanol is converting methane to syngas, either by steam reforming methane and carbon dioxide, or by catalytic conversion of methane. (Conventional technologies for this part of the process can be expensive; however, several companies are developing new technologies to reduce this expense.) Next, a catalytic process converts syngas to crude methanol. Finally, distillation purifies the crude methanol to chemical grade.



Converting syngas to methanol

For More Information...

Changing energy markets worldwide are prompting producers of coal and other fuels to look at new markets for coalbed methane. Coalbed methane is a potential feedstock for methanol and other products. Use of coalbed methane is also beneficial in that it also reduces emissions of this greenhouse gas to the atmosphere.

To obtain more information about methanol production, and uses of methanol for transportation, contact:

Greg Dolan
Communications Director
American Methanol Institute
800 Connecticut Avenue, NW, Ste. 620
Washington, DC 20006

phone: (202) 467-5050
fax: (202) 331-9055
e-mail: AmMethInst@aol.com
http://www.methanol.org

Or contact the U.S. EPA's Coalbed Methane Outreach Program for information about this and other profitable uses for coal mine methane:

Coalbed Methane Outreach Program
U.S. EPA
401 M Street, SW (6202J)
Washington, DC 20460 USA
(202) 564-9468 or (202) 564-9481
Fax: (202) 565-2077
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UPGRADING MEDIUM QUALITY COAL MINE GAS BY BLENDING AND SPIKING

Typical pipeline equipment required for blending coal mine gas with higher heating value gas

BLENDING AND SPIKING ARE COST EFFECTIVE APPROACHES TO MEETING PIPELINE SPECIFICATIONS BECAUSE...

- These processes blend gob gas or other "below spec" coal mine gas with high heating value gas from pre-drainage wells, conventional natural gas, or propane
- They can be used either as stand-alone processes or in conjunction with enrichment
- They are proven processes in both the conventional natural gas and coal mine methane industries
- Upgrading helps increase the use of coal mine methane, which reduces greenhouse gas emissions

Spiking and blending can be inexpensive techniques for upgrading gob gas

Why Consider Spiking and Blending to Produce Pipeline Quality Coal Mine Gas?

A large portion of the methane emitted from coal mines comes from gob areas (collapsed roof rock over the mined out coal), where methane concentrations typically vary from 30 to 80%. For safety reasons, many mines drain gob gas, but often do not use it because pipelines typically require gas whose methane content is at least 95% (about 950 btu/ft^3). In some cases, however, medium-heating value coal mine gas can be blended with higher heating value gas and/or spiked with propane to produce marketable pipeline quality gas.

Blending is the process of mixing medium heating value gas with high heating value gas (blending gas) to achieve a blended gas that meets or exceeds minimum pipeline quality requirements. Spiking is the process of adding propane in order to boost the heating value up to pipeline quality. Spiking and blending, together with careful gob well monitoring, can result in pipeline quality gas that can be sold to consumers. In some cases, spiking and blending can cost-effectively supplement enrichment processes such as nitrogen and carbon dioxide rejection.

Spiking and blending do not require a gas processing facility

At least two coal mine methane project developers in the United States use blending and/or spiking to improve the quality of the gas they produce. The Noumenon Corporation of Core, West Virginia, is blending gas from West Virginia mines with high-Btu gas or propane and selling the product to several utilities. Stroud Oil Properties, Inc. blends coal mine gas from the abandoned Golden Eagle Mine in Colorado with coalbed methane that has a heating value of about 980 Btu, produced from a nearby field. Stroud sells the blended gas to the local pipeline.

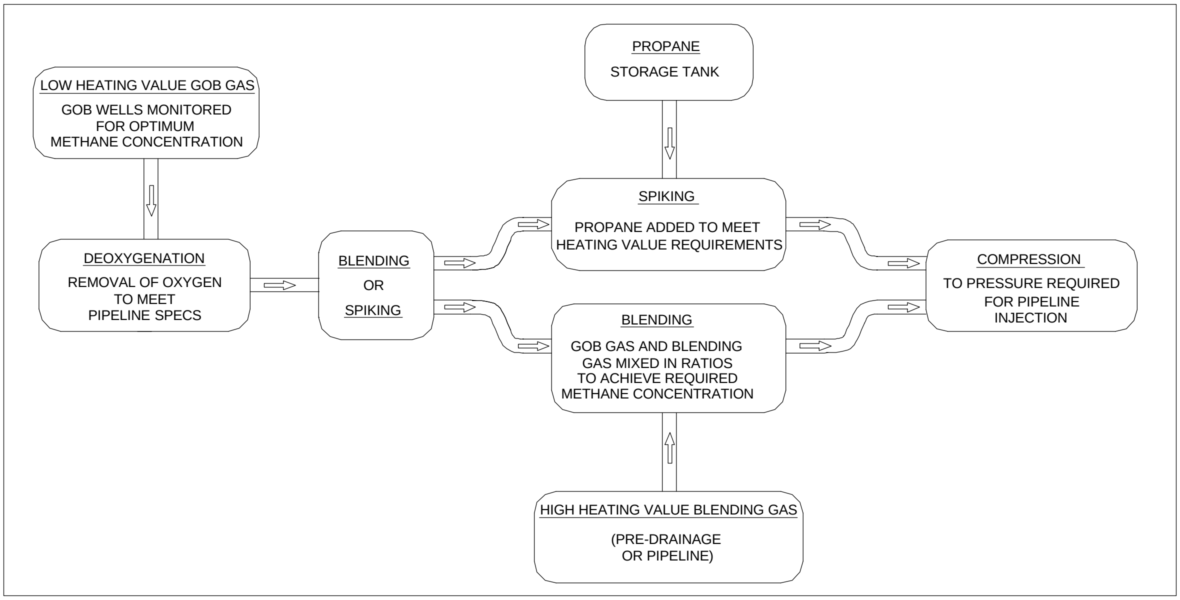
The quality of both the gob gas (or other "off-spec" gas) and the blending gas impact the feasibility of spiking and blending. Gas whose methane concentration exceeds 60% and whose oxygen concentration is less than 5% is most suitable for spiking and blending. Spiking and blending may work well with a broader, integrated strategy that includes improving gas recovery systems to enhance gas quality, and/or gas enrichment to remove contaminants such as nitrogen, oxygen, carbon dioxide, and water vapor.

U.S. EPA has developed software to help developers determine cost-effective

Under ideal circumstances, blending or spiking alone may dilute the contaminants in gob gas sufficiently to meet pipeline specifications. Often, however, it is necessary to remove water, moisture, and oxygen. The most expensive part of this treatment is deoxygenation, the capital cost of which is typically more than $450,000 to treat a 3 mmcf/d gob gas flow containing about 3% oxygen. Water separation and dehydration may each cost about $20-25,000 for similar gob gas flow rates. Despite these costs, projects that require gas cleanup prior to blending or spiking can still be economic.

Project costs and revenues vary widely depending on site specific conditions. U.S. EPA has prepared a computer model that helps gas project developers identify cost-effective combinations of enrichment, blending, and spiking options. The following page includes sample model inputs and outputs.

SPIKING AND BLENDING PROCESS



Sample Economics from the U.S. EPA Gas Upgrade Model

The model employs conservative capital and operating cost estimates for all parameters, including gas compression and enrichment. The table below shows sample model inputs and outputs for varying gob gas methane concentrations, and varying blending gas costs and propane prices. For this illustration, each case assumes that the total flow rate of gas (both high-heating value and gob) that can be drained from the mine is 10 mmcf/d, and that the pipeline requires 96% methane and no more than 4% inert gases. This illustration also assumes that there is sufficient high-quality coal mine gas recovered from the mine to use as blending gas, rather than purchasing natural gas.

In Case 1, the mine could upgrade its gas for $1.54/mmbtu using enrichment only, or for $1.48/mmbtu if it subsequently blended the enriched gob gas with high-heating value coal mine gas. If the mine were able to sell the gas at $2.00/mmbtu, it would net $0.46/mmbtu using enrichment only, and $0.52/mmbtu using a combination of enrichment and blending. In Case 2, enrichment followed by spiking would be the most profitable option, while in Case 3, enrichment alone would be most profitable.

Case	Inputs to Model					Outputs from Model (Cost to Upgrade in $/Mmbtu)		
	% Gob Gas	% Blending Gas	% of Methane in Gob Gas	Cost of Blending Gas[1] ($/mmbtu)	Cost of Propane ($/mmbtu)	Enrichment Only ($/mmbtu)	Enrichment Followed by Blending ($/mmbtu)	Enrichment Followed by Spiking ($/mmbtu)
1	32	68	82	$1.60	$4.10	$1.54	**$1.48**	$1.53
2	30	70	85	$1.75	$3.75	$1.50	$1.50	**1.47**
3	42	58	83	$1.70	$4.25	**$1.39**	N/A	N/A

[1] "Cost of blending gas" is the value of the high-heating value gas used for blending, i.e., the price at which the gas could be sold to a pipeline minus the assumed cost of compressing and transporting the gas to the pipeline

N/A = Value Not Available; if the model determines that enrichment only (i.e., not followed by blending or spiking) is the cheapest option (Case 3), it does not reveal the cost to blend or spike.

It is important to recognize that the above cases are illustrative only, and that a margin of error is inherent in the model. The model is designed for preliminary analysis only, and model users will need to conduct further technical and economic analyses before undertaking a project.

For More Information...

U.S. EPA's 1997 report, *Technical and Economic Assessment of Potential to Upgrade Gob Gas to Pipeline Quality*, and accompanying computer model examine various options for upgrading medium quality coal mine gas. To obtain the computer program and report, contact:

Coalbed Methane Outreach Program
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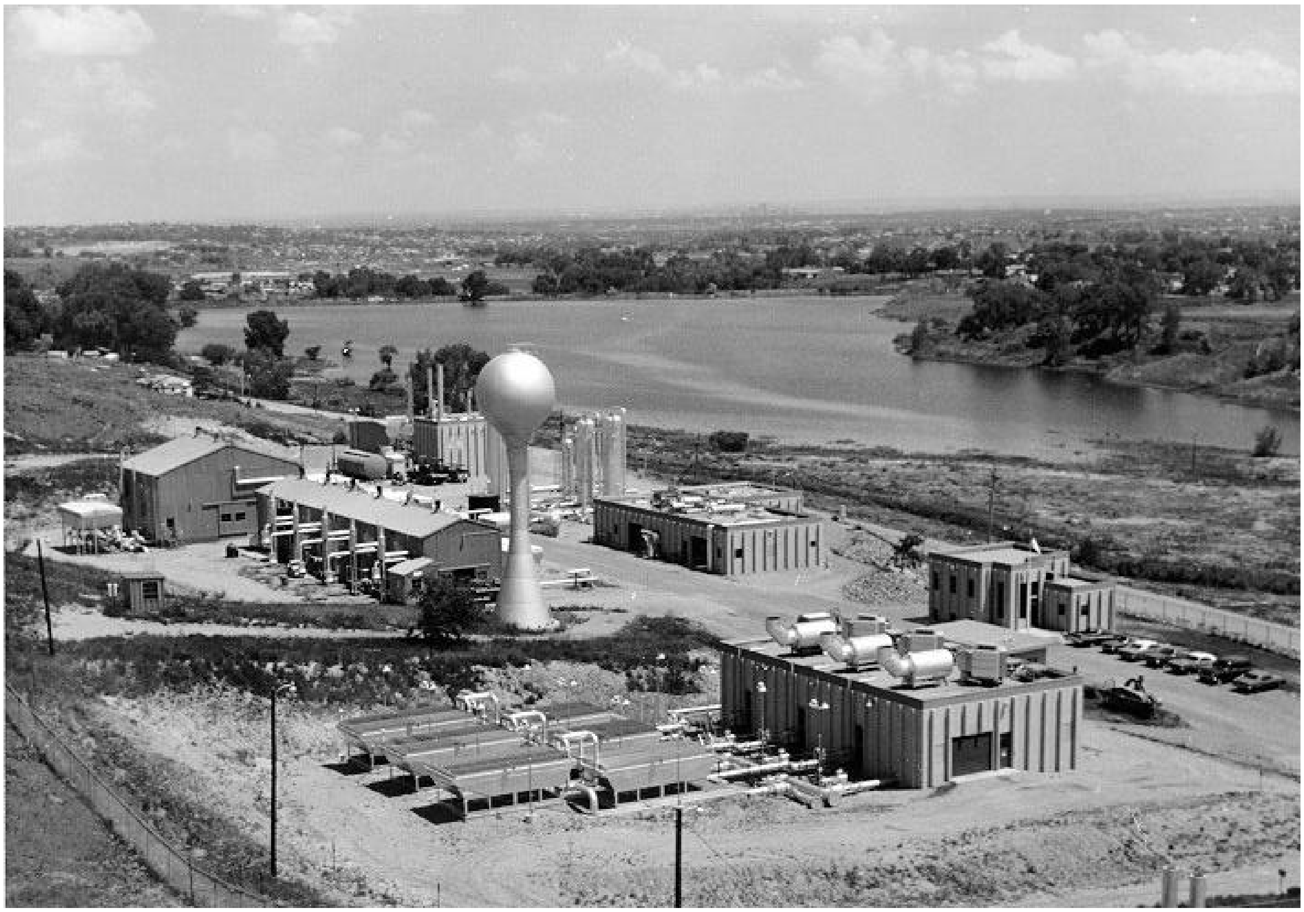
COAL MINE METHANE STORAGE IN ABANDONED MINES



Leyden Mine Underground Natural Gas Storage Facility Near Denver, Colorado
(Photo courtesy of Public Service Company of Colorado)

PRIMARY BENEFITS OF STORING COAL MINE METHANE IN ABANDONED MINES…

- Allows project operators to store excess gas and ensure consistent deliverability
- Can use the methane for peak shaving (supplying gas to market during peak demand)
- Could improve the overall economic viability of many coal mine methane projects

Peak load gas storage could improve the overall economic viability of many coal mine methane projects

Why Consider Storing Coal Mine Methane in Abandoned Mines?

The use of abandoned coal mines to store coal mine methane and conventional natura gas can enhance the economics of coal mine methane projects. Historically, the natura gas industry has used storage facilities to store gas during periods of low demand, particularl the summer months, and withdraw it during periods of peak demand, typically in the winte More recently, gas storage units include peak load facilities that are typically capable of hig deliverability with flexibility in injection and withdrawal cycles.

Accurate predictions of increases in gas demand are critical to market stability, particular during winter months. Unseasonable weather which leads to stored gas withdrawals ca send natural gas prices soaring. Storage facilities can benefit from these situations by sellin gas at peak prices. Demand for natural gas storage facilities has increased due to: 1) th high cost of constructing pipeline capacity, 2) FERC Order 636, and 3) increased natural ga demand.

To date, there has been no storage of coal mine methane in abandoned mines. In fac there is only one abandoned coal mine storage facility in the United States--the Leyden Min Underground Gas Storage Facility, operated by Public Service Company of Colorado (PSCo The facility, established in the late 1950s, remains a key component of Denver's natural ga supply system. Distrigaz, a Belgian gas company, has more extensive experience with storin gas in abandoned mines. Two facilities in the Campine coalfields store in excess of 10 billio cubic feet of imported natural gas for use during peak demand periods.

More than 18,000 coal mines abandoned after 1950 are located near the 22 gassiest mines

Continued success with conventional natural gas storage at the Leyden Mine and those i Belgium suggests that there may be many opportunities for storage of coal mine methane a abandoned mines located near active coal mines. The ability to store gas would benef coal mine methane projects that market recovered gas by injecting it into commercia pipelines. Specifically, these facilities would provide project operators with the ability to stor excess gas, sell gas during peak demand times, and assure consistent product deliverabilit to dedicated customers.

Gas storage could also enhance the viability of methane-fueled power projects. A ga storage facility permits the operator to supply gas at a nominal levelized price, improving th economics of a power generation facility. The profitability of a power generation projec ultimately depends on the cost of fuel, and the sales price the operator can receive fo electricity during times of low ("off peak") electricity demand. In addition to selling power t other consumers, a coal mine could use the electricity on-site to supplement power supplie by electric utilities.

Abandoned coal mines favorable for coal mine methane storage would typically hav mined-out seams deep below the surface, and undisturbed surrounding strata (e.g., roo and pillar without extensive pillar extraction). In some instances, there may be lowe development and operating costs with larger scale facilities, due to economies of scal More important than size, however, is the facility's proximity to gas sources and market which affects its ability to respond to changing markets.

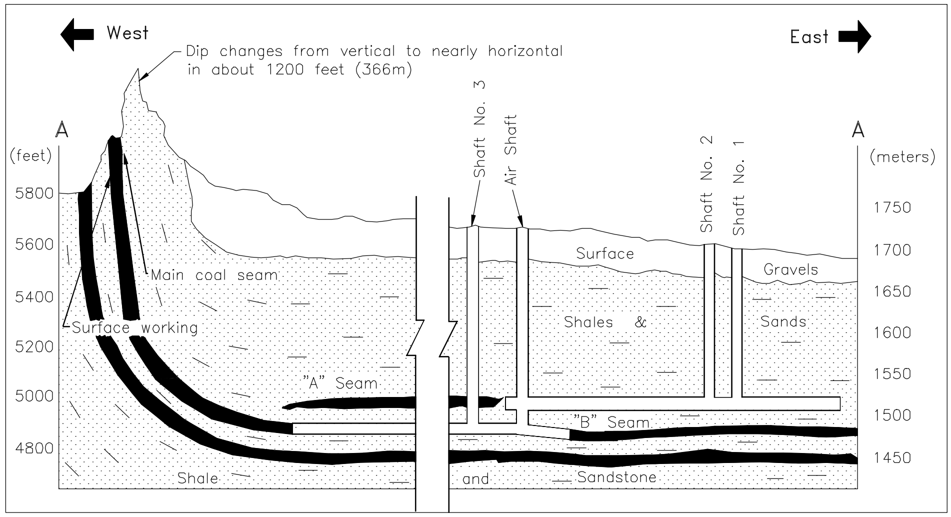
Abandoned mine gas storage may be particularly advantageous to larger coal mine methane projects that inject gas into commercial pipelines

Many abandoned coal mines have sufficient capacity to store more gas than the typic active mine produces, and could serve as storage facilities for conventional natural gas a well. This added capability could further enhance economics of the storage project b increasing the ability to maximize gas sales during peak gas prices. It could also increas opportunities to use medium quality coal mine methane, by blending it with gas tha exceeds pipeline quality (see U.S. EPA's Technical Options case study *Upgrading Mediu Quality Coal Mine Gas by Blending and Spiking*).

The Leyden Mine Underground Natural Gas Storage Facility

The Leyden Mine contains two horizontal coal seams, 8 to 10 feet thick, one 50 feet above the other. Room and pillar mining left a void of 150 million cubic feet (mmcf) some 700-1,000 feet below the surface. Operating pressure may vary from 60 pounds per square inch (psi) to 250 psi, but averages 165 psi.

Water-saturated shale and sandstone surrounding the coal seams provides the seal that keeps the gas from seeping out of the mine. Storage capacity of the facility is 3.0 billion cubic feet (bcf), and the working capacity is 2.2 bcf.



East-West Section of the Leyden Mine (modified from PSCo brochure)

Opportunities for Coal Mine Methane Storage in Abandoned Mines

Many active gassy coal mines are in close proximity to abandoned underground mines, and the availability of high-deliverability gas storage nearby could enhance coal mine methane recovery and use. Because abandoned coal mines are generally shallow, storage pressures, and hence storage capacities tend to be low relative to conventional depleted gas reservoirs and aquifer storage facilities. However, the potential for added storage via re-adsorption of methane by the unmined coal can significantly increase storage capacity. Belgian operators indicate that this effect increases storage volumes in their abandoned coal mine storage facilities by a factor of ten.

EPA has prepared a report titled *Technical and Economic Assessment of Coalbed Methane Storage in Abandoned Coal Mine Workings*. The table below shows estimated capital and operating costs.

Comparison of Development and Operating Costs for Conventional vs. Abandoned Mine Storage

	Conventional Storage Facilities	**Hypothetical Abandoned Mine Storage Facility**
Development Cost	\$2-4/mcf (\$70-135/1000 m^3) for depleted reservoirs and aquifer storage \$7-14/mcf (\$245-500/1000 m^3) for mined caverns	\$5.90 - \$6.50/mcf (\$208-\$230/1000 m^3)
Operating Cost*	\$0.20-4.50/mcf of gas sales (\$7-159/1000 m^3)	\$2.00-\$2.80/mcf of gas sales (\$71-99/1000 m^3)
* Per single cycles. Multiple cycles further reduce operating costs.		

The EPA report includes preliminary economic analysis for hypothetical abandoned mine storage facilities operating with oversupply gas stock from associated large scale coal mine methane projects. An \$11 million capital investment in a facility that can withdraw gas at 80 mmcf/d (2.3 million m^3/d), cycling 35 maximum gas withdrawal days per year, and selling gas at an average annual peak price of \$2.50/1000 ft^3 (\$88.29/1000 m^3), would yield the following results:

- internal rate of return greater than 15%;
- net present values greater than \$1 million (discount rate 5%);
- project payback period of less than five years.

For More Information...

The use of abandoned coal mines to store coal mine methane can enhance the economics of coal mine methane projects, allowing project operators to store oversupply gas, and sell it during periods of peak demand (and consequently higher gas prices). To obtain the EPA report *Technical and Economic Assessment of Coalbed Methane Storage in Abandoned Coal Mine Workings,* or to obtain additional information about this and other uses for coal mine methane, contact:

Coalbed Methane Outreach Program
U.S. EPA (6202J)
401 M Street, SW (6202J)
Washington, DC 20460 USA
(202) 564-9468 or (202) 564-9481
Fax: (202) 565-2077
e-mail: fernandez.roger@epa.gov
schultz.karl@epa.gov

http://www.epa.gov/coalbed

To obtain more information about the Leyden Mine Underground Storage Facility, contact:

William Uding
Public Service Company of Colorado
1123 W. 3rd Avenue
Denver, CO 80223
(303) 571-3127
Fax: (303) 893-1758
e-mail: buding@psco.com

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November 1998

EPA Coalbed Methane Outreach Program Technical Options Series

CONVERSION OF COAL MINE METHANE INTO SYNTHETIC FUELS

Commercial scale gas-to-liquids plant in Pueblo, Colorado fueled by landfill methane gas (1992)
(Photo courtesy of Rentech, Inc.)

COAL MINE METHANE USE IN SYNFUEL PRODUCTION…

- Use of coal mine methane as a feedstock gas can improve synfuel economics
- Produces high-quality liquid fuels that can be easily transported
- Ideal for methane recovered from coal mines without pipeline access
- Use of coal mine methane reduces greenhouse gas emissions
- Can operate on medium-quality gob gas

Coal mine methane may be a low-cost alternative to conventional natural gas for small gas-to-liquids plants

Why Consider Coal Mine Methane for Synfuel Production?

For safety reasons, many gassy underground coal mines drain methane from their coal seams. Most coal mines vent this methane to the atmosphere, which not only represents the loss of a valuable fuel source, but also contributes to global warming, as methane is a potent greenhouse gas. While an increasing number of coal mines recover methane for pipeline injection, mines producing medium quality gas (typically less than 80% methane), or those not located near pipelines, look to other gas-use options. Recently, there has been a renewed interest in the conversion of methane into liquid hydrocarbon fuels such as diesel, kerosene, and naphtha. Because liquids can be transported more efficiently than gas, energy producers are developing methane-to-liquid fuel technologies in areas where pipeline facilities may not be economically justified. As a result, locating a synfuel plant near a coal mine could enhance the economic viability of both methane recovery and synfuel production.

Although gas-to-liquids technologies have existed since the 1920s, the capital cost of conversion plants has hindered the economic feasibility of synfuels production. The most successful conversion of methane to liquid fuels to date is through Fischer-Tropsch Synthesis technology. The discovery of advanced catalysts during the past decade has greatly reduced the costs of the technology, thus making methane conversion plants smaller than 5,000 barrels per day economically possible. Currently, Syntroleum Corporation refines the Fischer-Tropsch chemistry using a proprietary catalyst that allows up to 30% N_2 and CO_2 in the feedstock gas. Using an iron-based catalyst, Rentech, Inc. successfully converts gas with methane concentrations as low as 40%. In addition, the Department of Energy is working with Air Products and Chemicals, Inc. to develop a novel ceramic membrane that could reduce the cost of converting natural gas to transportation-grade liquid fuels by 50%.

Synthetic fuels are environmentally superior to conventional petroleum products

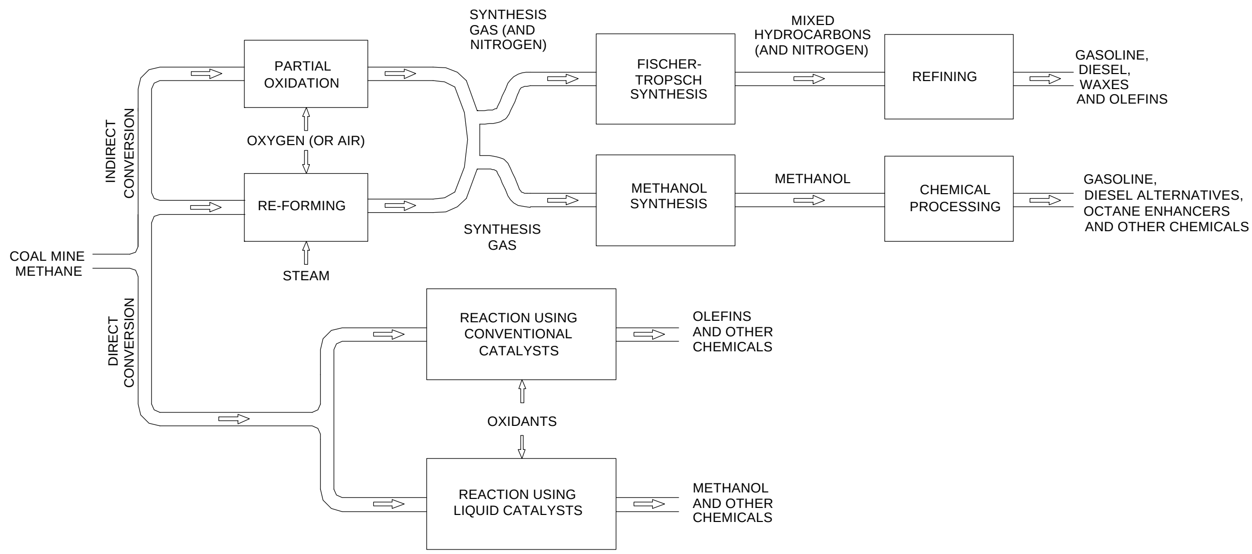
The products produced from these conversion processes are environmentally superior to many fuels because they are free of aromatics, nitrogen, and sulfur, and have a high centane number (clean burning properties). The quality of synthetic diesel fuel produced by the Fischer-Tropsch process is excellent, and therefore would be of special interest to underground coal mines operating or considering operating diesel equipment. In fact, these properties make synthetic diesel suitable as a blending component for upgrading conventional diesel fuels to meet stringent mining specifications.

Some Facts About Synfuel Production…

- Ten thousand cubic feet (10 mcf) of methane will produce approximately one barrel of liquid products
- Plant sizes typically range from 2,000 to 20,000 barrels/day, but smaller plants may be feasible if low cost gas is available
- At $0.50–1.00/mcf of methane, feedstock gas costs are $5-10/barrel, while estimated operating and maintenance costs (at 5,000 barrels/day) are $5-6/barrel
- Typical 1998 synthetic diesel prices are about $US 27 to $32 per barrel (typically $8/barrel more than conventional diesel prices)

The market for high-quality diesel is increasing worldwide

SYNTHESIS FUEL FLOW CHART



In an era of increasing environmental concerns, high-quality, sulfur-free diesel is readily sold on worldwide markets. For example, Royal Dutch/Shell Group produced synthetic diesel at its 12,500 b/d plant in Malaysia and sold it in California, because it met the stringent emission standards imposed by the California Air Resources Board. Moreover, the Mine Safety and Health Administration (MSHA) proposed a rule in April 1998 to reduce diesel particulate matter in underground coal mines. As a result, diesel engines used in these mines may require particulate filters in the future. Synthetic diesel use can reduce particulate emissions by up to 30%. In addition, synthetic diesel can reduce NO_x emissions (which represent a major problem for diesel engine exhaust) by 10%. U.S. EPA is proposing new diesel engine emission standards in 1999 for a wide range of highway and off-road applications. Coal mine methane-produced synthetic fuels could help reduce emissions that cause ground-level ozone (primarily NO_x and particulate matter).

The success of coal mine methane recovery and use requires a reliable market for the gas, and synfuel plants seek ample (five million standard cubic feet per day or more) methane sources. A coal mine or a group of coal mines located close together could supply low-cost methane feedstock to gas-to-liquid plants. In return, the mines would have access to high-quality diesel and other fuels to meet the fuel needs of their mining equipment. The recovery of coal mine methane for use as a synfuel feedstock reduces emissions of this greenhouse gas into the atmosphere.

PROPERTIES OF HIGH-QUALITY SYNTHETIC DIESEL

FUEL PROPERTIES	MSHA RECOMMENDATIONS	CONVENTIONAL DIESEL	SYNTHETIC DIESEL
Centane Number*	> 48	40-57	> 65
Aromatic Content	< 20%	<35%	< 1%
Sulfur Content	< 0.05%	<0.25%	< 0.0001%

* The centane number refers to the volatility of a fuel. Higher numbers indicate lower hydrocarbon emissions.

For More Information…

The continued development and refinement of gas-to-liquid technologies offers opportunities for coal mine operators and synfuel producers. Synfuel production provides a market opportunity for gassy coal mines without ready access to pipelines, while producers of liquid synthetic fuels may find the opportunity to purchase low-cost coal mine methane attractive.

To obtain more information about gas-to-liquids technologies, contact:

Mark Koenig
Rentech, Inc.
1331 17th Street
Suite 720
Denver, Colorado 80202
(303) 298-8008
Fax: (303) 298-8010

John Ford
Syntroleum Corporation
1350 South Boulder
Suite 1100
Tulsa, Oklahoma 74119
(918) 592-7900
Fax: (918) 592-7979

Or contact EPA's Coalbed Methane Outreach Program for information about this and other profitable uses for coal mine methane:

Coalbed Methane Outreach Program
U.S. EPA (6202J)
401 M Street , SW
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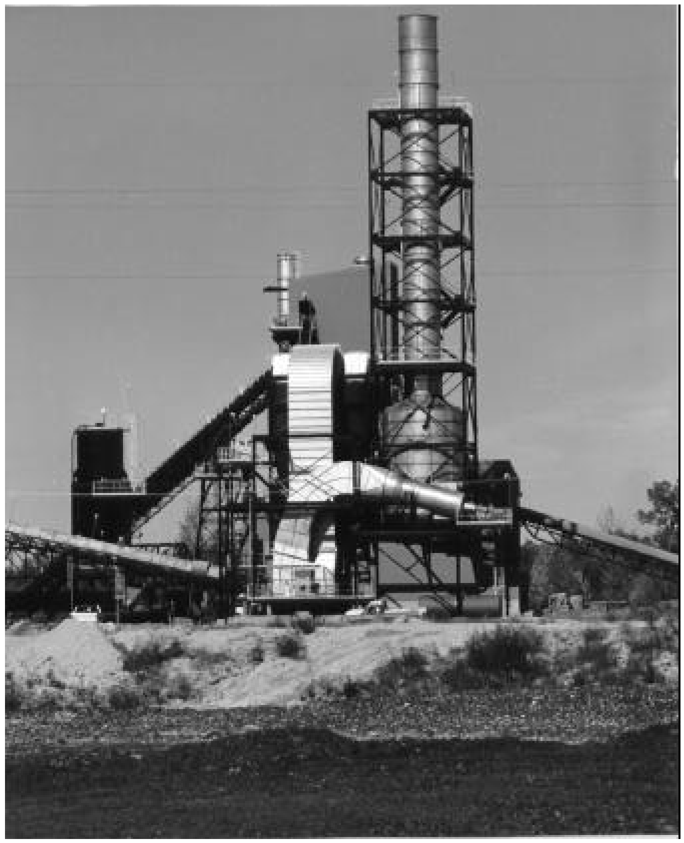
EPA Coalbed Methane Outreach Program Technical Options Series

Use of Coal Mine Methane in Coal Dryers



The thermal coal dryer at Jim Walter Resources' No. 4 Mine
is capable of burning coal or natural gas
(Photo Courtesy of Jim Walter Resources, Inc.)

BENEFITS OF USING COAL MINE METHANE IN THERMAL DRYERS...

- Better heat distribution from gas firing results in reduced grate bar maintenance costs
- Reduced corrosion of wetted parts due to reduction of H_2SO_4 from firing coal
- Eliminates emission of fine particulate material resulting from coal-fired heating
- Can use medium quality gas from gob wells
- Recovery and use of coal mine methane reduces greenhouse gas emissions

Use of coal mine methane in thermal dryers can free up coal for sales, while employing coal mine gas that does not meet pipeline specifications

Why Consider Using Coal Mine Methane in Thermal Dryers?

Product moisture is usually a specification item in a coal sales contract, because reduced moisture facilitates handling during shipment, reduces heat loss during the combustion process, and decreases transportation costs. To meet these requirements, coal preparation plants ("prep plants") often use thermal dryers, which produce a heated air stream that drives off moisture from the coal. Thermal dryers typically burn coal to heat the air stream, but prep plants located at gassy coal mines may find it more economical to burn recovered coal mine methane to provide this heat.

Many preparation plants worldwide have used coal mine methane for drying coal, including those at the Pniówek Mine in Poland, the Buchanan Mine in Virginia, and the Severnaya Mine in Russia. The Buchanan Mine, for example, uses nearly 1.5 million cubic feet of coal mine methane per day for this purpose. The use of coal mine methane for coal drying has several advantages, including 1) reduced operating and maintenance costs; 2) freeing-up of additional coal for sale; and 3) reduction in SO_2, NO_x, and particulate emissions to the atmosphere. The economic viability of burning coal mine methane in a thermal dryer may vary depending on the market for the gas, value of coal being substituted by gas, and the current value of emission credits being saved by burning gas. An added benefit is that the use of coal mine methane reduces emissions of this greenhouse gas to the atmosphere.

Operational costs of thermal dryers are reduced 10% by using gas burners

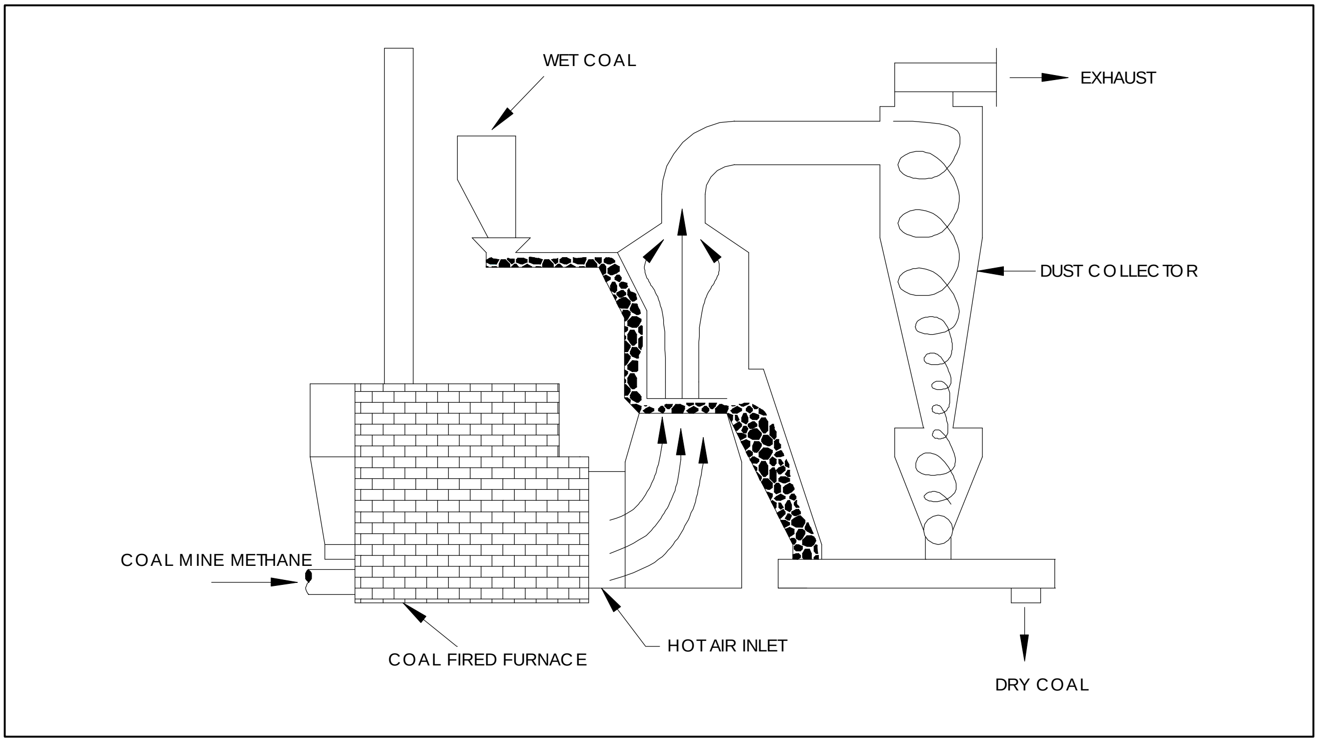
The two principle methods of drying coal are through mechanical or thermal processes. The mechanical process typically employs a centrifugal device that generally dries the coal to about a 12% moisture content. Since many coal sales contracts require lower moisture contents, thermal dryers are more widely used, as they are capable of drying coal to a 3-6% moisture content. There are several types of thermal coal dryers, including rotary direct dryers, fluidized direct dryers, flash dryers, and indirect coal dryers, all of which use combustion burners to produce hot air or steam for drying coal.

In order to adapt an existing coal-fired thermal dryer to operate on coal mine methane, the primary modification would be the addition of one or more gas burners. Rather than removing the coal-firing equipment from the dryer, the prep plant could leave it in place, providing the option to fire either type of fuel.

Using coal mine methane as fuel reduces SO_2, NO_x, and greenhouse gas emissions

The amount of methane that a thermal dryer requires depends on the amount of water that must be evaporated. This, in turn, depends on the amount of coal fed to the dryer and the percentage of water in the dried product, which can vary widely from site to site. For illustration purposes, however, drying one short ton of coal at 3% moisture in a fluidized direct dryer requires about 400,000 Btu of thermal energy. In order to dry 380 short tons of coal per hour (9,120 short tons per day), the dryer would require about 3.7 mmcf of methane per day, or about 156 tons of coal per day in fuel. The dryer also requires nearly 2 MW of electricity to operate.

Coal Mine Methane in Thermal Dryers



In addition to using coal mine methane to supply thermal energy to dry the coal, prep plants can use it to generate the electricity needed to convey, feed and pulverize the coal being dried. A typical 380 ton per hour coal dryer requires nearly 400,000 Btu of thermal energy and 2 MW of electricity to operate.

> **Use of Coal Mine Methane at the Severnaya Mine Coal Preparation Plant**
>
> In Russia's Vorkuta Coal Basin, the Severnaya Mine coal preparation plant uses coal mine methane in its coal dryer. In 1995, the mine recovered more than 350 million cubic feet of methane for use in the drying unit. Mine management reports that the use of coal mine methane improved the dryer's efficiency, reliability, and ease of use, and saves nearly 25 thousand short

Using coal mine methane lowers particulate emissions, which reduces the overall load on the coal dryer's pollution control equipment. The use of coal mine methane to fuel thermal dryers can also free up additional coal for sales. This would be particularly attractive to coal prep plant operators that currently burn saleable, higher quality coal in their thermal dryers.

Estimated Cost of Installing Gas Cofiring Equipment in Thermal Dryers ($US)

Two burner assemblies	250,000
Electric motors and starters	5,000
Constant gas pilots	10,000
Delivery	10,000
Installation and Engineering	125,000
Total	**400,000**

For More Information...

Many gassy coal mines are seeking ways to utilize gob gas that does not meet pipeline specifications. Coal mines with prep plants on site or nearby may find that gob gas provides an ideal alternative to coal for fueling thermal dryers.

To obtain more information about the potential for using gas in thermal coal dryers, contact:

Ike Miller
Roberts & Schaefer Company
Central Operation
120 South Riverside Plaza
Chicago, Illinois 60606
(312) 236-7292
Fax: (312) 726-2872

Or contact EPA's Coalbed Methane Outreach Program for information about this and other profitable uses for coal mine methane:

Coalbed Methane Outreach Program
U.S. EPA (6202J)
401 M Street, SW
Washington, DC 20460 USA
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e-mail: fernandez.roger@epa.gov
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http://www.epa.gov/coalbed

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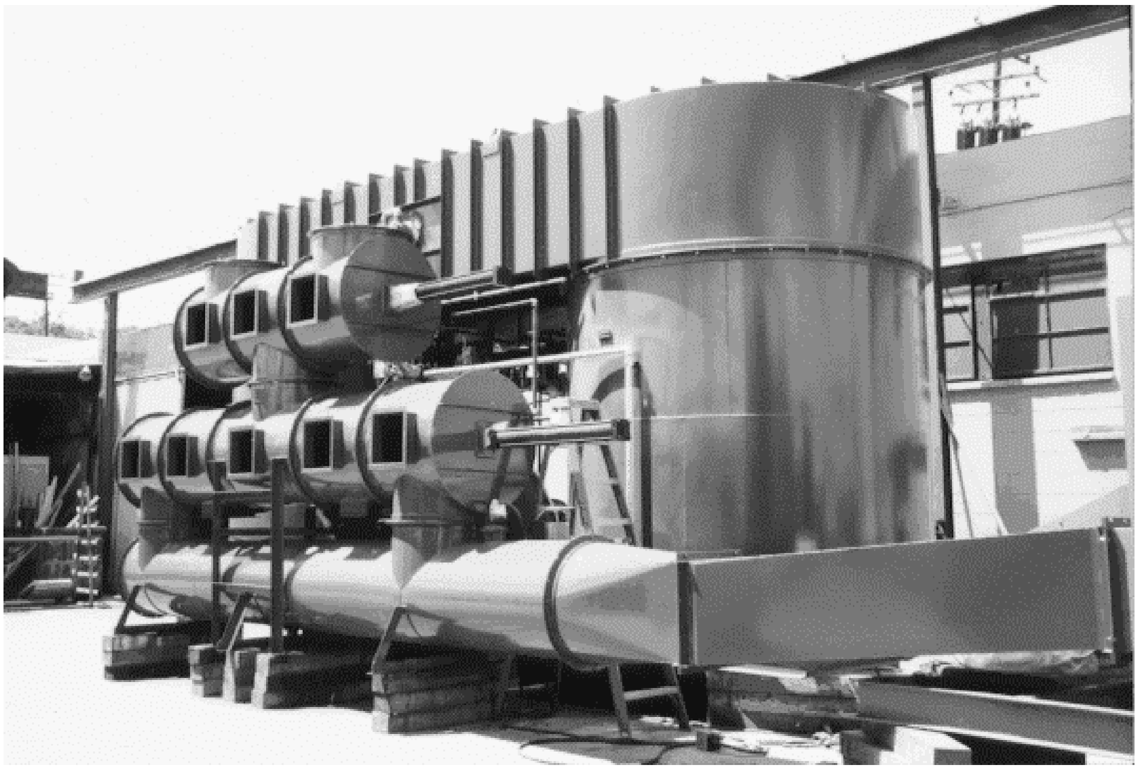
CONVERSION OF COAL MINE VENTILATION AIR INTO ENERGY USING OXIDATION TECHNOLOGIES



Regenerative thermal oxidizers recover heat energy by oxidizing low-concentration fuels
(Photo courtesy of Ship & Shore, Inc.)

USING COAL MINE VENTILATION AIR, OXIDIZERS CAN...

- Operate efficiently using gas with high air volume/low methane concentrations typical of coal mine ventilation exhaust
- Recover up to 75% of the heat energy they produce
- Heat mine facilities and dry coal or slurry
- Produce thermal energy for use on-site at coal mines, or at nearby facilities such as boilers, steam turbines or electricity generators

Oxidation of coal mine ventilation air is a new application of a well-established technology

Why Consider Using Mine Ventilation Air in Oxidizers?

For safety reasons, most coal mines worldwide dilute the methane liberated during coal mining operations to a concentration of less than 1%. At such low concentrations, it is difficult to use this methane gas mixture as a fuel. Oxidation technologies (which heat gases to their oxidation temperatures, converting the vapors to CO_2 and water) have long been used for the treatment of volatile organic compound (VOC) emissions, and will soon be tested with coal mine methane. Through high heat recovery, oxidizers provide a way to use ventilation air as heat energy while reducing methane emissions.

There are two primary types of oxidation technologies that can effectively oxidize methane: **thermal and catalytic**. Thermal oxidizers can utilize either a regenerative heat exchanger (direct contact heat exchange on inert material beds) or recuperative type (conventional, indirect heat exchangers) in their processes. Both thermal and catalytic oxidizers can be operated under unidirectional or reverse-flow conditions. Each type operates over a wide range of air flow rates and dilute methane concentrations. The systems produce excess thermal energy that mines could use for electricity generation, heating, cooling, and drying processes.

Regenerative oxidizers are self-sustaining at methane concentrations as low as 0.1%

The **regenerative thermal oxidizer** passes ventilation air through an inert bed of high heat capacity material (i.e. silica gravel or ceramic material) to a central combustion zone. Due to its stability, the methane molecule requires temperatures in excess of 1,000°C to automatically oxidize in air. Thermal energy resulting from this combustion heats up the media on the exhaust side of the bed. The flow is reversed allowing preheating of the incoming ventilation air. As a result, a relatively small amount of energy produces surplus heat, which can be evacuated through heat transfer piping.

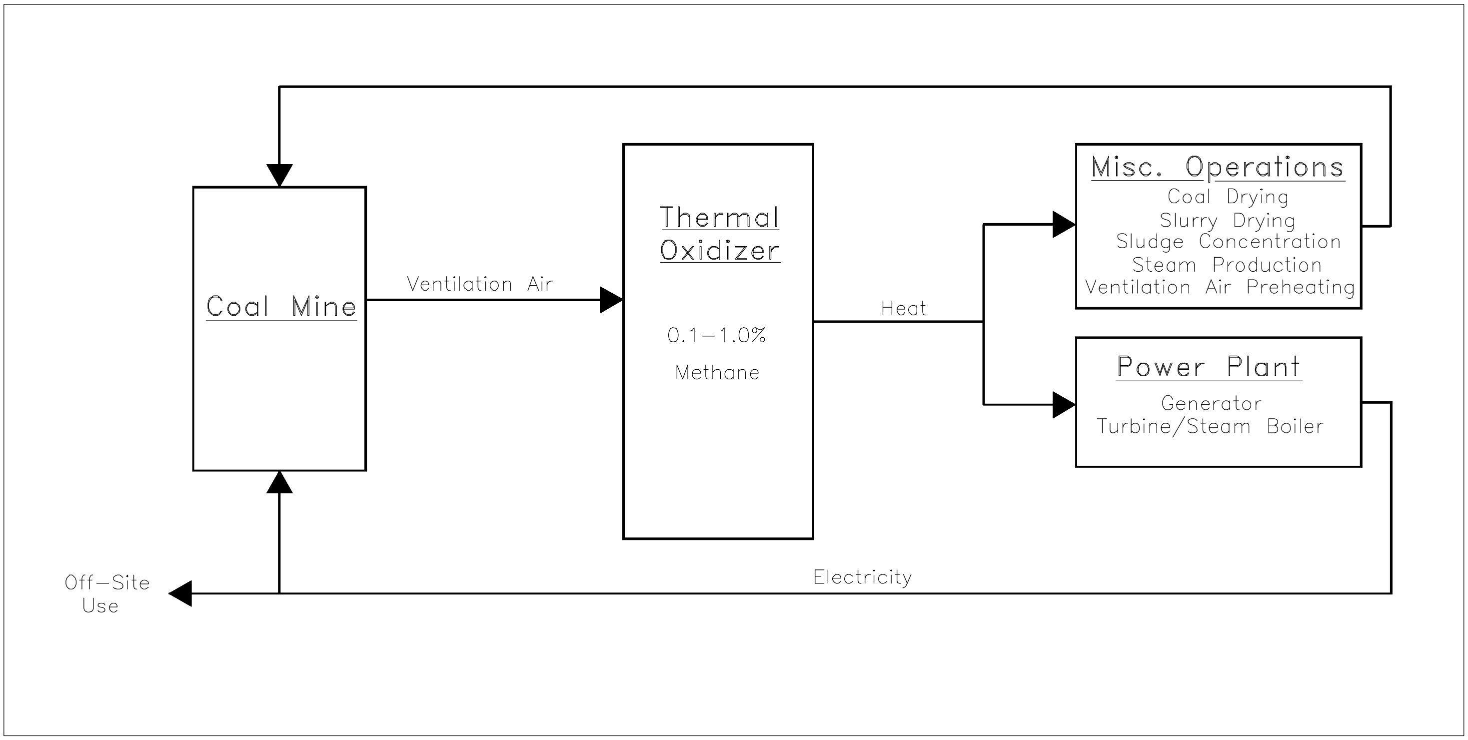
Operating at lower temperatures (500°C to 800°C), the **catalytic oxidizer** uses a burner in addition to a chamber bed to promote the oxidation of methane. Upon reaching a preheated temperature, the system reduces burner input to maintain the required catalyst inlet and outlet temperatures. Usually, the catalyst consists of a bed of metal or metal oxide substrate in the shape of pellets, which can be replaced and/or regenerated periodically. It should be noted that certain unidirectional catalytic oxidizers have difficulty oxidizing low concentrations of methane, and may be unsuitable for mine ventilation air.

The **reverse-flow catalytic oxidizer** combines the processes of heat exchange with the use of a catalyst. Storing heat in inert beds upstream and downstream of the catalyst section ensure a full methane conversion, in addition to promoting a high heat recovery rate. As a result, a coal mine can choose a more economical catalyst to lower operating costs. Neill & Gunter (Nova Scotia) Ltd. is currently co-operating with Natural Resources Canada and others in the development of this technology. An industrial demonstration is envisaged for the Spring of 1999.

High heat recovered (75%) is usable as thermal energy

While the above three methane oxidation technologies appear to be the most promising for methane use to date, other types of methane oxidizers may prove effective in the future.

Using Coal Mine Ventilation Air With Thermal Oxidizers



Typical Parameters Of Methane Oxidation Systems

- Can operate at methane concentrations typical of coal mine ventilation air (0.1-1.0% volume)
- Primary heat recovery ranges from 50-75%
- Recovers heat at temperatures between 500-900°C, depending on oxidizer type
- Can operate on high air flow rates ranging from 30,000-200,000 scf per minute
- Approximate installed costs range from $US 800,000 -1,200,000 (depending on the size of the facility)
- Can produce 25-35 MW of thermal energy

For More Information...

Coal mine operators and energy producers have long sought a means of using the low concentration methane contained in ventilation air. Thermal and catalytic oxidizers provide coal mines with several options for converting ventilation air into usable energy while reducing greenhouse gas emissions.

To obtain more information about using oxidizers to convert coal mine ventilation air into energy, contact:

Anoosheh Mostafaei
John Von Bargen
Ship & Shore, Inc.
2474 N. Palm Drive
Long Beach, CA 90806
(562) 997-0233
Fax: (562) 997-0667

Brian King
Neill And Gunter (Nova Scotia) Limited
PO Box 2190
East Dartmouth
Nova Scotia, Canada B2W3Y2
(902) 434-7331
Fax: (902) 462-1660

Or contact EPA's Coalbed Methane Outreach Program for information about this and other profitable uses for coal mine methane:

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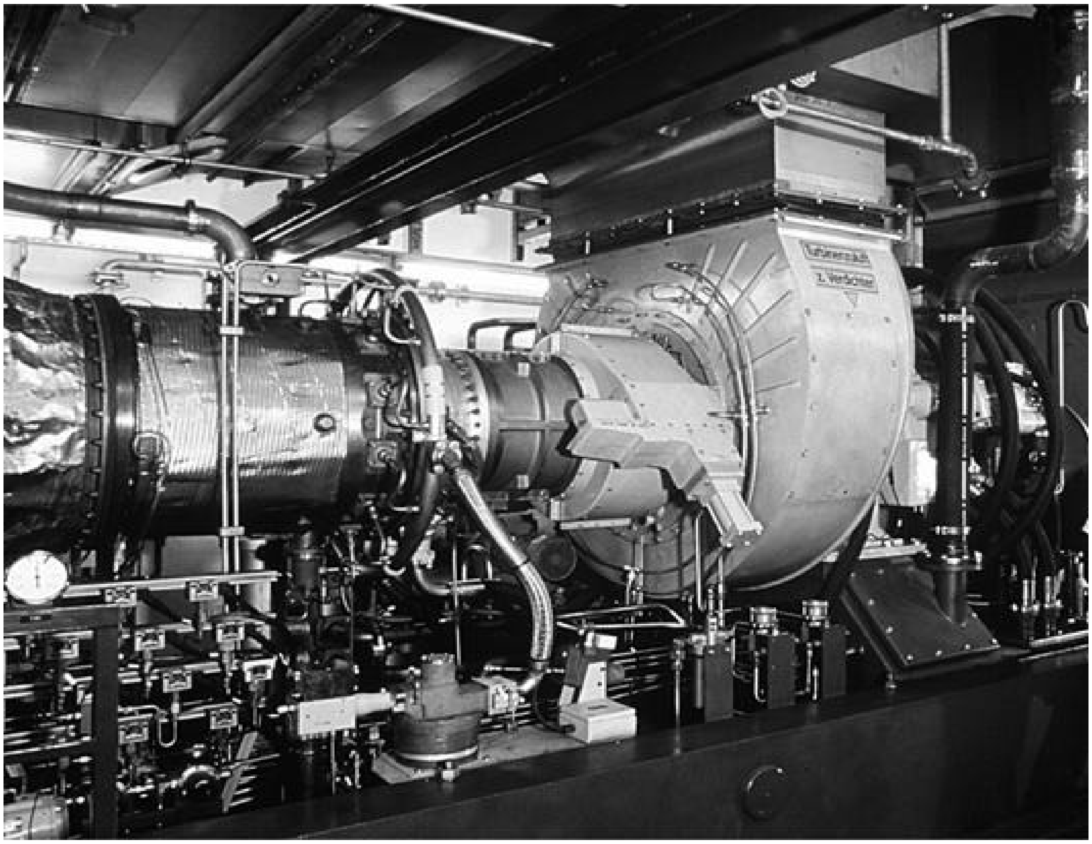
GENERATING ELECTRICITY USING COAL MINE METHANE-FUELED TURBINES



Gas turbines are a low-cost electricity production option when inexpensive gas is available
(Photo courtesy of Solar Turbines Incorporated)

APPLICATIONS AND BENEFITS INCLUDE…

- Off-grid self-generation of electricity at remote gas production sites
- Wide range of sizes available, from 500 kW to 25 MW
- Ability to use with cogeneration and combined cycle technologies
- Ideal for gob gas use, as they can operate on gas with a heating value as low as 350 Btu
- Recovery and use of methane reduces greenhouse gas emissions
- Reliable and proven technology

Gas turbine technology is proven and reliable

Why Consider Using Coal Mine Methane to Fuel Gas Turbines for Electricity Generation?

A large portion of the methane emitted from coal mines comes from gob areas (collapsed rock over mined out coal), where methane concentrations typically vary from 30 to 80%. Gas with a methane concentration less than 95% is usually not suitable for pipeline injection. As a result, coal mines frequently do not use this medium-quality gas and instead vent it to the atmosphere, contributing to global warming. However, gas with a methane concentration exceeding 35% (such as coal mine gas) can in fact be used as fuel for on-site electricity generation.

The use of gas turbine technology for electricity generation is proven and reliable, and coal mines in Germany, Great Britain, Japan, China and Australia have successfully used coal mine methane-fueled gas turbines. Multiple gas turbine configurations designed to meet specific efficiency and application requirements are available. These include turbines capable of running on gob gas with variable methane concentrations, turbines with low NO_x emissions, and those capable of waste heat recovery for cogeneration and combined cycle applications.

Gas turbine exhaust can be used with cogeneration and combined cycle technology

In recent years manufacturers have made many improvements in the materials used in turbine parts. These improvements result in greater efficiencies, longer service life, and lower overall maintenance costs. Turbines using medium quality (35% to 75% methane) fuel are currently available. At least one manufacturer is developing a gas turbine capable of using low quality fuel (< 7.5% methane). In the future, gas turbines capable of using fuel with such a low heating value may be able to run on enriched coal mine ventilation air.

Installed costs for gas turbines suitable for coal mine use range from $650/kWh to $1000/kWh. The largest operating cost is fuel, which can be minimized by using gob gas. It may be possible to realize further savings by using mine ventilation air for combustion air in the turbine. Assuming a purchase price of $0.04 /kWhr for electricity from a utility, a coal mine generating its own electricity could save $1 million per year for each 5 MW of utilized generation capacity.

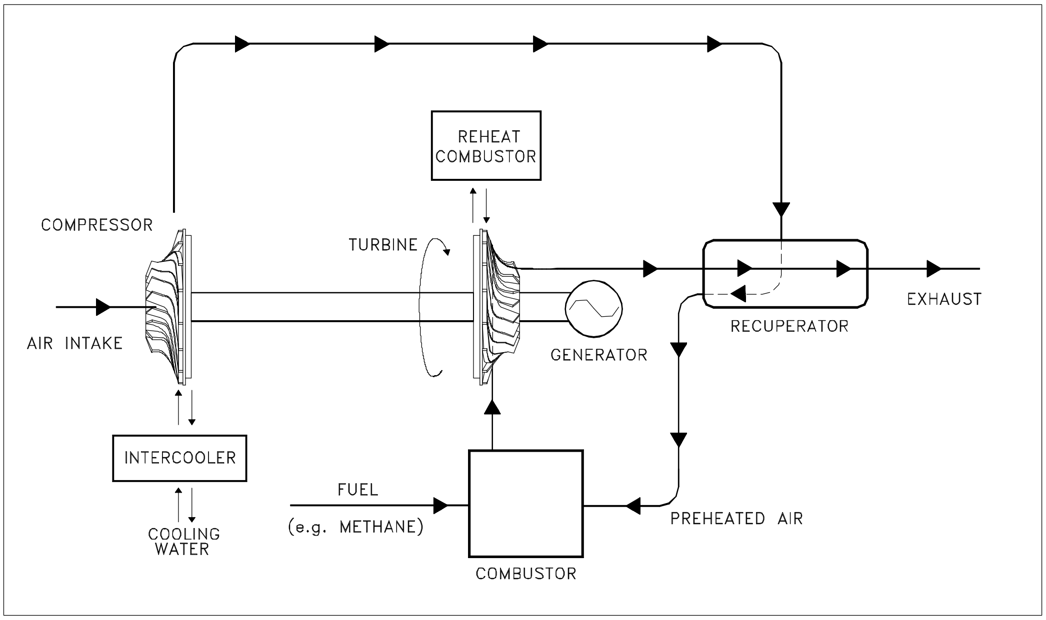
In today's changing power market, the trend toward distributed generation will allow consumers to determine their own power generation sources. Gas turbines may be a good choice for coal mines with unutilized methane resources. Many turbine manufactures have training programs, maintenance agreements and lease options available to turbine purchasers. In many cases, a coal mine may be able to realize substantial savings by using coal mine methane to generate electricity on-site.

Some Facts About Gas Turbines…

- Mines can recover exhaust energy for heating buildings or drying coal
- Modular design allows for easy installation
- Trailer mounted units permit flexibility in siting and fast installation
- "Medium btu" turbines normally operate over a range of 35% to 75% methane

Gas turbines have a low energy density (output to size ratio)

HOW A GAS TURBINE OPERATES



Gas turbine operation is a relatively simple process. First, a pressure gradient draws air into a compressor stage in the turbine. An intercooler at this stage increases compressor efficiency by cooling the intake air, thereby increasing its density. The compressed air exits the compressor stage through an exhaust heat recuperator, which preheats the compressed air to increase combustion efficiency. The preheated compressed air is then mixed with fuel and combusted. The resulting hot gas expands through the turbine, producing the mechanical energy required to generate electricity and operate the compressor stage of the turbine. Some turbines use a reheat combustor to maximize the combustion and expansion of the gas through the turbine. The hot exhaust gas is then passed through the heat recuperator to preheat the incoming compressed air.

Comparison Of Gas Turbines With Other Power Generation Technologies

	GAS TURBINE	MICRO TURBINE	IC ENGINE	FUEL CELL
Capacity (kW)	1000-50000	30-2000	10-4000	3-3000
Efficiency	21%-42%	22%-30%	12%-20%	40%-65%
Typical Installed Cost ($US/kW)	650-1000	350-700	600-1000	900-3000
Maintenance cost ($US/kWhr)	0.003-0.008	0.003-0.01	0.015-0.025	0.005-0.01

For More Information...

Rapidly changing electricity markets are creating new opportunities for on-site power generation using coal mine methane. Gas turbines may be a cost-effective power generation option for some gassy underground coal mines.

To obtain more information about generating electricity using gas turbines, contact:

Ken Berg
Solar Turbines, Incorporated
600 East Crescent Avenue, Suite 305
Upper Saddle River, NJ 07458
Telephone: (201) 825-8200
Fax: (201) 825-8454

There are also many other gas turbine manufacturers worldwide. The Internet site **www.gasturbines.com** maintains an extensive list of gas turbine manufacturers, including contact information, specifications and prices.

Or contact EPA's Coalbed Methane Outreach Program for information about this and other profitable uses for coal mine methane:

Coalbed Methane Outreach Program
U.S. EPA (6202J)
401 M Street , SW
Washington, DC 20460 USA
(202) 564-9468 or 564-9481
Fax: (202) 565-2077
e-mail: fernandez.roger@epa.gov
schultz.karl@epa.gov

http://www.epa.gov/coalbed

United States Environmental Protection Agency | Air and Radiation 6202J | Draft November 1998

EPA Coalbed Methane Outreach Program Technical Options Series

USING MINE VENTILATION AIR AS COMBUSTION AIR IN ENGINES AND TURBINES

Appin Power Plant, New South Wales, uses mine ventilation air as combustion air in its IC engines
(Photo courtesy of Energy Developments Limited)

A PROVEN TECHNOLOGY FOR USE OF LOW QUALITY MINE GAS

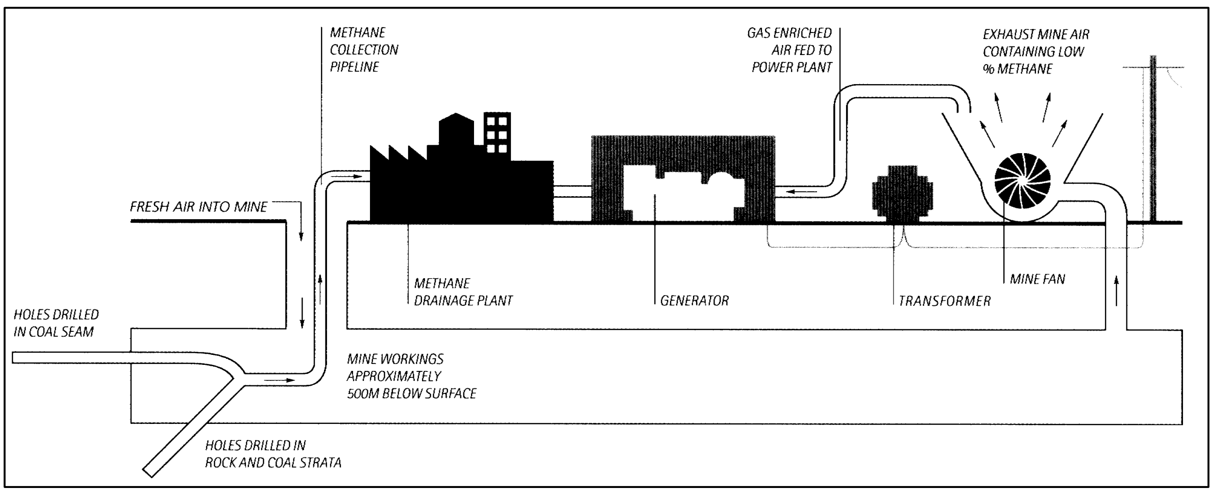
- Significantly increases overall output of internal combustion (IC) engines
- Use in IC engines is commercially proven at the Appin Power Plant, New South Wales, Australia
- Potentially economical for use in gas turbines in cases where the coal mine can supply gob gas or other low cost methane as the primary fuel
- Reduces overall emissions of methane, a potent greenhouse gas

Ventilation Air Use in Internal Combustion Engines

Mining of underground coal deposits releases large quantities of methane into the mine workings, which mines must remove by diluting the methane with large volumes of air. Many gassy mines, like the Appin and Tower Collieries in New South Wales, Australia, also drain methane by drilling boreholes into the coal seams and surrounding strata in advance of mining. The mines then pipe this methane to the surface.

In the past, the Appin and Tower Collieries emitted to the atmosphere most of their drained methane and all of the methane contained in the ventilation air. In 1996, however, Energy Developments Limited (EDL) began maximizing the use of this methane when they installed coal mine methane-powered generating plants at Appin and Tower. There are 54 one-MW internal combustion (IC) engines at Appin, and 40 such engines at Tower. The project sells most of the resulting power to a local utility grid, and sells a portion to BHP Steel for use at the mines.

The Appin and Tower power plants use all of the gas produced during methane drainage operations at both mines, lowering their greenhouse gas emissions. ***The Appin Colliery also uses methane from its ventilation air as feed air to the IC engines.*** This is the first project in the world to commercially use mine ventilation air. The mine uses electric vacuum pumps to route ventilation air through its upcast shaft, then ducts it to a filtration system to remove particulates before piping it as a supplementary fuel to the generator sets.



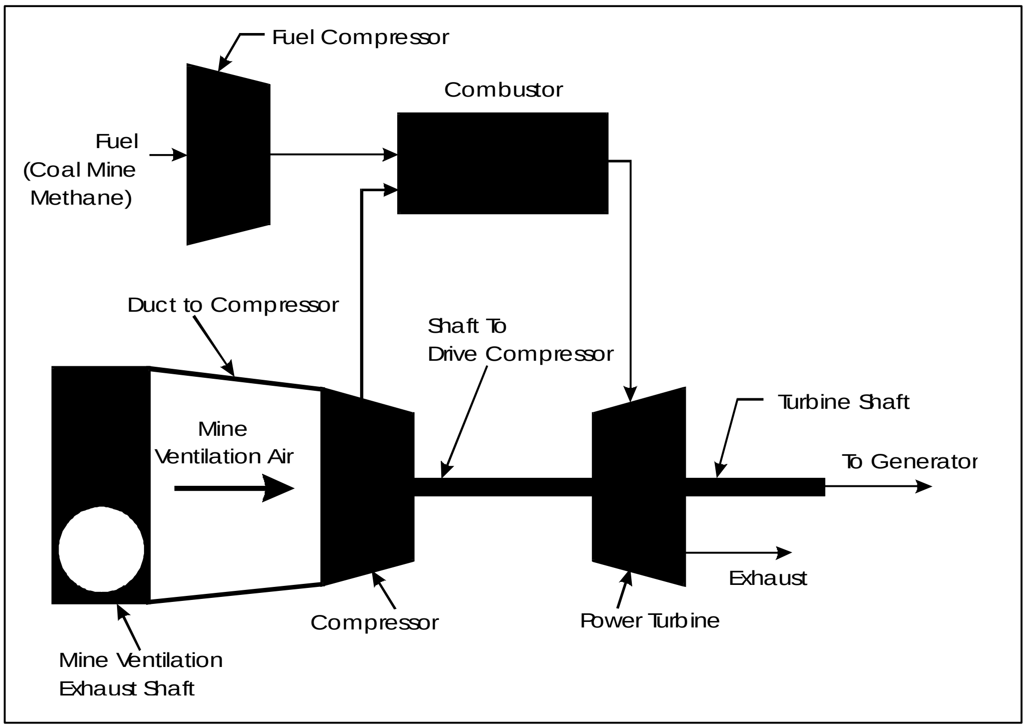
Use of methane at the Appin Colliery for power generation in IC engines

Some Facts About the Use of Mine Ventilation Air at the Appin Power Project...

- Use of methane from ventilation air as fuel increases overall plant output by 7 to 10%
- Appin can use 2,295 ft^3 (65 m^3) of ventilation air per second to produce 4-8 MW of electricity (depending on the methane content of the ventilation air)
- Ventilation air supplied to the engines typically contains 0.5 to 1.0 percent methane
- Appin recovers up to 1,306 mcf (37,000 m^3) of methane per day from ventilation air

Ventilation Air Use in Gas Turbines

Gas turbines, like IC engines, require air to combust fuel and produce heat. Ventilation air can supply most or all of the combustion air required, while methane that the mine drains can supply the primary fuel. A gas turbine is a simple device that consists of an air compressor, combustors, a power turbine, and an electric generator. Gas turbines are less capital intensive than coal-fired power plants, and are available in a large range of sizes. Ideally, the mine should locate the gas turbine adjacent to the mine's ventilation exhaust shaft in order to minimize the transportation cost of the ventilation air.



Schematic of Simple Cycle Gas Turbine Using Ventilation Air (Not to Scale)

The combustion air requirements of a gas turbine depend on its generating capacity. The combustion air required for simple cycle gas turbines is approximately 353 ft^3 (10 m^3) per hour of air per kW of installed turbine capacity, based on manufacturer operating and design data for turbines in the 1 to 100 MW size range. The more complex combined cycle plants require slightly lower air flows.

Preliminary estimates indicate that ventilation air containing 0.5% methane would supply 4-12% of a turbine's energy requirements, depending on operating pressures, temperatures, model selected, and other site-specific conditions. Northwest Fuel Development, Inc. demonstrated the technique in the early 1990's, using an air mixture of 0.5% to 1.5% methane in the combustion air, and proved that the turbine used less fuel than it would with ambient air as combustion air. At present, EPA is further researching the potential for using coal mine methane, and coal mine ventilation air, in gas turbines.

For More Information...

Changing electricity markets, coupled with environmental concerns associated with emissions of greenhouse gases to the atmosphere, are prompting coal and electricity producers worldwide to take a new look at the methane contained in mine ventilation air. Using this methane as combustion air for internal combustion engines and gas turbines enhances the productivity and economics of gas-fired power projects, while reducing emissions of methane to the atmosphere.

To obtain more information about using coal mine methane as combustion air in gas engines at the Appin Power Project, contact:

Mr. William Lazarus
General Manager
Energy Developments
P.O. Box 535
Richlands, QLD 4077
Australia
Tel: (61) (7) 3275 5555
Fax: (61) (7) 3217 0733

To obtain more information about gas turbines, contact:

Solar Turbines, Incorporated
600 East Crescent Avenue, Suite 305
Upper Saddle River, NJ 07458
Tel: (201) 825-8200
Fax: (201) 825-8454

Or contact EPA's Coalbed Methane Outreach Program for information about this and other profitable uses for coal mine methane.

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The mention of products or services in this case study does not constitute an endorsement by EPA.

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EPA Coalbed Methane Outreach Program Technical Options Series

USING COAL MINE METHANE TO HEAT MINE VENTILATION AIR

Coal mine methane-fueled heater at one of the Jim Walter Resources mines in Alabama
(Photo courtesy of Jim Walter Resources, Inc.)

BENEFITS OF USING COAL MINE METHANE TO HEAT VENTILATION AIR

- Reduces costs by displacing other fuels that are used to heat ventilation air
- Uses a fuel that is readily available at gassy coal mines
- Reduces emissions of methane, a greenhouse gas, to the atmosphere
- Heating ventilation air in winter increases worker comfort and productivity, and reduces equipment problems

Use of coal mine methane on-site for heating ventilation air at gassy mines is potentially profitable

Why Consider Using Coal Mine Methane to Heat Ventilation Air?

Coal mines must force large quantities of air through their workings to dilute methane for safety reasons. During the winter months, this ventilation air can become very cold, causing discomfort to miners, lowering worker productivity, and resulting in mechanical problems. In cold climates, such as that of the Russia's Kuznetsk Basin, heating of ventilation air is essential. Even in mild climates, such as the southern United States, heating ventilation air during the winter months can be beneficial in terms of comfort and productivity.

The use of coal mine methane, rather than other fuels, to heat ventilation air can be an economical choice for gassy mines interested in this opportunity. Rather than purchasing natural gas, propane, fuel oil or diesel to heat mine ventilation air, it may be cheaper for the mine to use recovered methane. Some coal mines (for example, those in the Kuznetsk Basin) currently use coal-fired boilers to heat their ventilation air. Replacing some or all of this coal with coal mine methane would allow the mine to sell more coal. Use of coal mine methane is also beneficial to the environment, in that it reduces emissions of methane, a greenhouse gas, to the atmosphere.

CMOP can provide technical and financial modeling support to coal companies interested in a site-specific analysis

Gassy coal mines that currently drain methane and wish to recover it for heating mine ventilation air could accomplish this goal in several ways. The mine could use direct-fired heaters installed in the ventilation duct or mine shaft. An alternative approach would be to burn the coal mine methane in some type of combustor containing a flue for venting combustion products, and use a heat exchanger to heat the ventilation air. The financial analysis below assumes the use of a direct-fired heater.

EPA Financial Analysis

EPA's Coalbed Methane Outreach Program (CMOP) prepared an analysis to compare the cost of using recovered coal mine methane for heating ventilation air to the cost of using purchased fuel for this purpose. The analysis of any coal mine methane recovery project requires estimates of methane flow and availability at the mine. This case study builds on the following gas and financial assumption information:

Gas Availability and Use

For this illustration, the study assumes that the mine:

- produces an average of 4 million tons of coal each year;
- liberates 550 cubic feet of methane per ton of coal mined;
- uses approximately 375,000 cubic feet of ventilation air per minute;
- does not currently heat its mine ventilation air, but desires a ventilation air temperature increase of 20^{o} for 6 months/year;
- would require 29,400 mmBtu of fuel annually to achieve this temperature; and,
- produces enough methane from existing gob wells to meet this demand (nearly 33 million cubic feet annually).

Cost[1]

Use of coal mine methane reduces emissions of this greenhouse gas to the atmosphere

The study assumes that project costs are as follows:

- *For Methane Use*: Capital costs are $94,000 (including direct-fired heater with controls, skid mounted compressor, and 1000 ft. of installed pipeline); annual operating cost is $8,000.
- *For Other Fuel Use*: Capital costs are $50,000 (for a direct-fired heater); it was conservatively assumed that there are no operating costs.

[1]These are standard cost assumptions used in most first-order CMOP financial analyses of ventilation air use.

Financial Assumptions

The analysis makes the following financial costs and assumptions:

- the project will have a 20-year life;
- annual inflation rate is 4%;
- the real discount rate is 6%;
- the tax rate is 27.5%; and
- 100% equity project financing.

Results of the Analysis

Because the mine is not currently heating its ventilation air, the analysis is a comparison of the cost of using recovered methane to heat ventilation air vs. the cost of other fuels. The following tables list the results of the analysis. Because it is strictly a cost comparison, the analysis does not include an internal rate of return or years to payback. The net present value for all fuel prices is negative, since the mine is not currently heating its ventilation air, and the model does not attempt to quantify benefits.

Use of Coal Mine Methane		
Capital Cost ('$000)	Annual Operating Cost ('$000)	**NPV ('$000)**
$94	$8	**$-150**

Use Of Alternative Fuel			
Fuel Cost [1] ($mmBtu)	Capital Cost ('$000)	Annual Fuel Cost ('$000)	**NPV ('$000)**
$3.00	$50	$92	**$ -783**
$5.00	$50	$153	**$-1,272**
$8.50	$50	$260	**$-2,128**

[1]To put these purchased fuel costs in perspective, following are typical purchase prices for various fuels, in $US per mmBtu: Natural gas - $4.75–5.75; Fuel Oil (Diesel) - $4.00-$5.00; Propane - $6.50-8.50; Electricity - $13.00-14.50.

The results of this analysis suggest recovering coal mine methane to heat mine ventilation air would be cheaper than using purchased fuels, even when the cost of purchased fuel, and equipment costs associated with using purchased fuel, are unusually low. The model does not attempt to quantify the productivity benefits that the mine could realize as a result of providing a more comfortable working environment for underground personnel. However, these productivity benefits could be significant for mines located in areas with cold winters.

To refine this analysis would require additional inputs such as actual methane emissions data, the cost of displaced fuel, and actual capital and operating costs for all alternatives. CMOP can provide the necessary technical and financial modeling support to coal companies interested in a site-specific analysis.

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